AD-A089 146 BECHTEL NATIONAL INC SAN FRANCISCO CA F/G 13/2
FLUE GAS DESULFURIZATION AT NAVY BASES, NAVY ENERGY GUIDANCE ST--ETC(U)
AUG 80 A I MCCONE N68305-77-C-0003
UNCLASSIFIED CEL-CR-80.023 NL

1 of 3
AD A
089146

AD-A089146

LEVEL

CR 80.025

CIVIL ENGINEERING LABORATORY
Naval Construction Battalion Center
Port Hueneme, CA

Sponsored by
NAVAL MATERIALS COMMAND

FLUE GAS DESULFURIZATION AT NAVY BASES, NAVY ENERGY GUIDANCE STUDY, PHASE IV

August 1980

An Investigation Conducted by
BECHTEL NATIONAL, INC.
Fifty Beale Street
San Francisco, CA

[illegible]

[illegible]

(18) CEL

Unclassified

SECURITY CLASSIFICATION OF THIS PAGE (When Data Entered)

REPORT DOCUMENTATION PAGE

READ INSTRUCTIONS BEFORE COMPLETING FORM

1. REPORT NUMBER (12) CR-80.023	2. GOVT ACCESSION NO. AD-A089 146	3. RECIPIENT'S CATALOG NUMBER
4. TITLE (and Subtitle) (6) Flue Gas Desulfurization at Navy Bases, Navy Energy Guidance Study, Phase IV		5. TYPE OF REPORT & PERIOD COVERED (9) Final rept., August 1980
		6. PERFORMING ORG. REPORT NUMBER
7. AUTHOR(s) (10) A. I. McCone		8. CONTRACT OR GRANT NUMBER(s) (15) N68305-77-C-0003
9. PERFORMING ORGANIZATION NAME AND ADDRESS Bechtel National, Inc. Fifty Beale Street San Francisco, CA (12) 234		10. PROGRAM ELEMENT, PROJECT, TASK AREA & WORK UNIT NUMBERS (17) 63724N; Z0840 Z0840-01, Z0840-01-014
11. CONTROLLING OFFICE NAME AND ADDRESS Civil Engineering Laboratory Naval Construction Battalion Center Port Hueneme, CA (11)		12. REPORT DATE August 1980
		13. NUMBER OF PAGES 210
14. MONITORING AGENCY NAME & ADDRESS (if different from Controlling Office) (16) Z0840		15. SECURITY CLASS. (of this report) Unclassified
		15a. DECLASSIFICATION/DOWNGRADING SCHEDULE

16. DISTRIBUTION STATEMENT (of this Report)

Approved for public release; distribution unlimited.

17. DISTRIBUTION STATEMENT (of the abstract entered in Block 20, if different from Report)

18. SUPPLEMENTARY NOTES

19. KEY WORDS (Continue on reverse side if necessary and identify by block number)

Energy; Fuels; Coal; Coal combustion; Air pollution control; Stack gas scrubbers; Flue gas desulfurization

20. ABSTRACT (Continue on reverse side if necessary and identify by block number)

A study of the availability, costs, and operating performance of industrial-sized flue gas desulfurization (FGD) systems for coal-fired boilers ~~was performed~~ for the Civil Engineering Laboratory at the Naval Construction Battalion Center at Port Hueneme, CA. The work was performed as Phase IV of Contract N68305-77-C-0003 entitled "Navy Energy Guidance Study". were studied.

DD FORM 1473 1 JAN 73 EDITION OF 1 NOV 65 IS OBSOLETE

Unclassified

SECURITY CLASSIFICATION OF THIS PAGE (When Data Entered)

410800 slr

410760

generic overview analysis showed that conventional soda liquor scrubbing offered lowest costs and highest performance when environmental permits can be obtained for disposal of liquid wastes. When wastes must be in solid form, the lowest costs are offered by conventional limestone, lime, and double alkali calcium-based throwaway processes. Several processes still under development were identified as promising but not yet proven. A site specific study identified three industrial-sized FGD installations with inherent availabilities in excess of 98% ~~percent~~.

The contract called for consideration and general comparison of lime, limestone, double alkali, sodium carbonate, sodium sulfite-bisulfite (Wellman-Lord), activated charcoal, and other candidate technologies.

Six technologies identified as commerically available were selected for examination as current technologies. Several additional technologies not yet applied on a commercial scale in the U.S. were selected as representative or possible future technologies.

Cost and performance comparisons were prepared for the current technologies on a generic or typical basis. However, comparative costs and suitability of FGD systems are quite site dependent, and site specific limitations should be studied on a case-by-case basis prior to any actual applications. A comparison of approximate levelized life-cycle costs is reported for the current technologies. Each levelized cost includes a capital charge based on vendor quotes and operating costs based on resource consumption and manning. It is shown that costs for the calcium-based throwaway processes (lime, limestone, and double alkali) do not differ significantly within the limits of the cost estimates. Costs for soda liquor scrubbing with liquid waste disposal are slightly lower. Costs for soda liquor scrubbing with waste crystallization are slightly higher than for the calcium throwaway processes. The Wellman-Lord/Allied Chemical recovery type process, which is not considered practical at sizes smaller than 400 x 10^6 Btu/hr, has, as expected, a cost significantly higher than the other five processes. Life-cycle costs for the Chiyoda CT-121, the Davy S-H, the magnesium-gypsum double alkali, and the spray dryer/baghouse processes are expected to be similar to those for the current calcium-based throwaway processes.

In the light of its previous operating record in the U.S., the Research-Cottrell/Bahco scrubber is a prime candidate for Navy bases where the associated solid waste disposal can be accommodated. If additional information confirms the preliminary

findings on the Chiyoda CT-121, it may also be recommended for similar circumstances. The sodium hydroxide scrubber is preferred where environmental permits can be obtained for disposal of liquid wastes. Bechtel experience indicates that any of the current FGD technologies can be made equally reliable if they are designed properly.

The site studies did identify installations at three of the facilities which have experienced high reliability. These were the following:

- Research-Cottrell/Bahco - Rickenbacker AFB, Ohio - lime/limestone
- General Motors, St. Louis, Missouri - soda liquor
- Chiyoda CT-121, Scholz Station, Florida - limestone

The Wellman-Lord/Allied Chemical, the magnesium oxide, and the activated charcoal processes which regenerate SO_2 and convert it to a by-product are in general not recommended for Navy bases, because of the complexity of the processes, their high cost in small scale, their need for premium fuel (gas), and problems in marketing or disposing of small amounts of by-product sulfur.

Accession For	
NTIS GRA&I	☑
DDC TAB	☐
Unannounced	☐
Justification	
By	
Distribution/	
Availability Codes	
Dist	Avail and/or special
A	

ACKNOWLEDGMENTS

Bechtel thanks the contract monitor, D. E. Williams, of the Civil Engineering Laboratory for his review and comment on this study. Bechtel also expresses appreciation to those that made site visits possible: J. B. Rasor and Rickenbacker AFB for providing information on the Research Cottrell/Bahco lime/limestone flue gas desulfurization (FGD) system there; Chiyoda International Corporation and Gulf Power Corporation for the opportunity to visit the Chiyoda 121 pilot facility at Scholz Station in Florida; the Northern Indiana Public Service Corporation, Davy McKee Corporation, and Allied Chemical Corporation for the opportunity to visit the Wellman-Lord/Allied Chemical FGD system demonstration plant at Mitchell Station near Gary; General Motors Corporation for the opportunity to visit their soda liquor FGD system in St Louis; and Firestone Corporation and FMC Corporation for the opportunity to visit the double alkali pilot plant at the Firestone plant in Pottstown, Pennsylvania.

12372

CONTENTS

Section		Page
7	RELIABILITY OF CURRENT TECHNOLOGIES	7-1
8	MAINTAINABILITY OF CURRENT TECHNOLOGIES	8-1
9	FUTURE TECHNOLOGIES	9-1
	9.1 Introduction	9-1
	9.2 Improved Lime and Limestone Wet Scrubbing Systems	9-2
	9.3 The Chiyoda Thoroughbred 121 Process	9-3
	9.4 Other Processes	9-5
	9.5 Suitability and Status of the Future Technologies	9-9
	9.6 Costs of Future Technologies	9-9
10	SITE STUDY PRELIMINARIES	10-1
	10.1 Introduction	10-1
	10.2 General Discussion of Facilities Studied	10-1
	10.3 Data Gathering	10-2
	10.4 Limited Character of the Analysis	10-3
	10.5 Quality of the Data	10-3
	10.6 Methodology for Reliability	10-4
	10.7 Methodology for Maintainability	10-8
	10.8 Methodology for Availability	10-9
11	GULF POWER CHIYODA CT-121 LIMESTONE SCRUBBER	11-1
	11.1 Introduction	11-1
	11.2 General Information	11-1
	11.3 Economics	11-2
	11.4 Efficiencies	11-2
	11.5 Configuration	11-3
	11.6 Operational Life Profile	11-3
	11.7 Reliability	11-3
	11.8 Maintainability	11-4
	11.9 Availability	11-9
	11.10 Comments on R and M Calculations	11-10
	11.11 Operation and Maintenance Facts	11-10

ILLUSTRATIONS

TABLES

Section 1

SUMMARY

1.1 INTRODUCTION

This document reports results of work performed under Phase IV of the "Navy Energy Guidance Study," contract N68305-77-C-0003, for the Civil Engineering Laboratory at the Naval Construction Battalion Center at Port Hueneme, California. The Phase IV study is entitled "Flue Gas Desulfurization System Application Study." Work on Phase IV was initiated on May 30, 1979. References 1 and 2 describe the work under Phases I, II, and III.

The objective of Phase IV is to examine the availability, costs, and operating performance of industrial-sized, coal-fired boiler flue gas desulfurization (FGD) installations, using generic overview analyses and also site specific studies. The results are intended to assist the Navy in deciding whether to include FGD systems in the coal-fired steam plants being planned.

The Phase IV study consists of three tasks:

- Technology Comparisons — Several flue gas desulfurization (FGD) technologies in a range of sizes were compared on the basis of cost and performance. This work is described in Sections 3 through 9 of this report

- Site Specific Studies — Operating histories of five industrial-sized FGD installations were obtained through site visits. This work is described in Section 10 through 15 of this report

- List of Installations — A list of operational coal-fired industrial FGD installations was prepared. This list appears in Section 16 of this report

In this report, the terms "FGD systems" and "scrubbers" are used interchangeably.

1.2 TECHNOLOGY COMPARISONS

The contract called for consideration and general comparison of lime, limestone, double alkali, sodium carbonate, sodium sulfite-bisulfite (Wellman-Lord), activated charcoal, and other candidate technologies.

Six technologies identified as commercially available were selected for examination as current technologies. Several additional technologies not yet applied on a commercial scale in the U.S. were selected as representative or possible future technologies.

Cost and performance comparisons were prepared for the current technologies on a generic or typical basis. However, comparative costs and suitability of FGD systems are quite site dependent, and site specific limitations should be studied on a case-by-case basis prior to any actual applications.

1.2.1 Assumptions in Technology Comparisons

The economic comparison of the current technologies presumed certain ground rules would govern the circumstances of operation:

- Each FGD system is attached to a coal-fired stoker boiler plant emitting 40 percent of the ash as fly ash
- A baghouse particulate removal system is provided upstream of the FGD system
- Enough land is available for an FGD system, whether part of a new boiler installation or retrofit to an already existing installation
- The coal is an Illinois Number 6 bituminous coal containing approximately 4 percent sulfur
- The FGD system will remove 90 percent of the SO_2

- Flue gas leaving the FGD system will be reheated

- FGD wastes will be hauled away and disposed of in an environmentally acceptable manner by a contractor for an annual fee

- Construction will be complete by May 1981, and the facilities will operate for 25 years

In this report is has been assumed that the standards ultimately promulgated for industrial boilers will require particulate and SO_2 removal levels similar to those now in force for public utility boilers. No federal air quality standards are currently in force for industrial-sized boilers. Standards for these boilers are currently under study by the Environmental Protection Agency (EPA). The Federal removal standards ultimately applied to industrial boilers may be less stringent than those assumed here. However, state and local regulations may require FGD systems even in the absence of Federal rules, especially in non-attainment areas.

1.2.2 Current Technologies

The five current technologies that were evaluated as candidates for coal-fired boiler installations at Navy bases are:

- Lime slurry wet scrubbing, yielding a blend of sludge and fly ash for dry landfill

- Limestone slurry wet scrubbing, yielding a blend of sludge and fly ash for dry landfill

- Sodium/lime double alkali process (sodium-based alkali wet scrubbing followed by sorbent regeneration with lime), yielding a blend of sludge and fly ash for disposal in a dry land fill specially constructed to minimize leaching of residual soluble sodium salts

- Soda liquor wet scrubbing (using sodium carbonate or caustic soda) followed by spent-liquor crystallization and disposal of the waste crystals in a landfill specially constructed to prevent leaching of the soluble salts

- Soda liquor wet scrubbing (using sodium carbonate or caustic soda) followed by forced oxidation of liquor sulfite to sulfate, pH adjustment, and disposal into an ocean or river as permitted by an appropriate governmental body

- Sodium sulfite - bisulfite wet scrubbing followed by spent-liquor regeneration and SO_2 recovery and conversion to elemental sulfur (Wellman-Lord/Allied Chemical Process). Disposal of a small purge of salt crystals will be similar to that for crystals from soda liquor scrubbing

1.2.3 Future Technologies

Technologies judged promising but not yet proven in industrial applications in the United States are:

- The Chiyoda Thoroughbred-121 (CT-121) process (using the jet bubbling reactor concept) with integral forced oxidation of calcium sulfite to sulfate (gypsum), yielding solids for dry landfill

- Spray dryer plus baghouse using lime slurry, yielding a dry solid waste suitable for landfill

Other representative technologies considered were:

- Activated charcoal absorption with SO_2 recovery and reduction to elemental sulfur

- Kawasaki magnesium – gypsum double alkali process, (wet scrubbing with a mixed slurry of calcium and magnesium compounds, and sorbent regeneration by lime addition and forced oxidation), yielding solids suitable for landfill

- Magnesium oxide regenerable process with magnesium oxide slurry scrubbing followed by sorbent calcining to magnesium oxide plus SO_2, and reduction of the SO_2 to elemental sulfur

In addition, in the near future, two improvements are expected which could enhance performance and/or operability of lime or limestone wet scrubbing installations with minimal retrofit. These are:

- Forced oxidation to convert the waste reaction products to calcium sulfate (gypsum) which is more easily compacted in dry landfill

- Organic acid or magnesium oxide additives to enhance SO_2 removal and improve scrubber performance and reliability

A German technology already incorporating these two improvements but not demonstrated in the U.S. is the final future process considered: The Davy S-H (Saarberg-Hoelter) Process.

1.2.4 Economic Comparison of Current Technologies

Table 1-1 compares approximate levelized life-cycle costs for the six current technologies. Each levelized cost includes a capital charge based on vendor quotes and operating costs based on resource consumption and manning, according to cost premises set forth in Sections 2 and 4. The table shows that costs for the calcium-based throwaway processes (lime, limestone, and double alkali) do not differ significantly within the limits of the cost estimates. Costs for soda liquor scrubbing with liquid waste disposal are slightly lower. Costs for soda liquor scrubbing with waste crystallization are slightly higher than for the calcium throwaway processes. The Wellman-Lord/Allied Chemical recovery type process, which is not considered practical at sizes smaller than 400×10^6 Btu/hr, has, as expected, a cost significantly higher than the other five processes.

1.2.5 Economics of Future Technologies

Life-cycle costs for the Chiyoda CT-121, the Davy S-H, the magnesium-gypsum double alkali, and the spray dryer/baghouse processes are expected to be similar to those for the current calcium-based throwaway processes.

1.2.6 Performance Ranking of Current Technologies

Table 1-2 provides rankings of the six current technologies in terms of the following four performance measures:

- Efficiency: Percent of entering SO_2 that can be comfortably removed by the process
- Operability: Probability of operating for one month without a forced shutdown

Table 1-1

APPROXIMATE LEVELIZED LIFE-CYCLE COSTS OF CURRENT TECHNOLOGIES
(1979 Dollars per Million Btu of Boiler Output)

3.39 percent sulfur coal, 90 percent removal

Installation Size (Boiler Plant Output)	Lime-stone	Lime	Double Alkali	Soda Liquor		Wellman-Lord/Allied Chemical
				Solid Waste	Liquid Waste	
50 Percent Load Factor						
400 x 10^6 Btu/hr	1.54	1.65	1.55	1.94	1.47	3.00
200 x 19^6 Btu/hr	1.90	2.01	1.92	2.23	1.78	
100 x 10^6 Btu/hr	2.29	2.40	2.31	2.69	2.04	
50 x 10^6 Btu/hr	2.93	3.05	2.96	3.34	2.59	
25 x 10^6 Btu/hr	4.29	4.39	4.31	4.69	3.66	
25 Percent Load Factor						
400 x 10^6 Btu/hr	2.55	2.66	2.57	2.95	2.04	5.09
200 x 10^6 Btu/hr	3.27	3.39	3.29	3.68	2.54	
100 x 10^6 Btu/hr	4.05	4.17	4.07	4.45	3.18	
50 x 10^6 Btu/hr	5.33	5.43	5.35	5.74	4.27	
25 x 10^6 Btu/hr	8.06	8.17	8.08	8.47	6.44	

Note: Levelized costs are life-cycle costs including discounted future costs. They are not the dollars per million Btu of boiler heat input costs conventionally calculated. Premises for these costs are provided in Sections 2 and 4.

Table 1-2

RANKINGS OF PERFORMANCE OF CURRENT TECHNOLOGIES
(Highest Ranking is 1)

Technology	Efficiency	Operability	Reliability	Maintainability
Limestone	4	3	2	2
Lime	3	3	2	2
Double Alkali	2	2	2	2
Soda Liquor (with Solid Waste)	1	2	2	2
Soda Liquor (with Liquid Waste)	1	1	1	1
Wellman-Lord/Allied Chemical	3	4	3	3

- Reliability: Ratio of scrubber operating hours per month to the sum of scrubber operating plus maintenance hours
- Maintainability: Probability that each failure can be repaired in one 8-hour work period

1.2.7 Sulfur Recovery Processes

The Wellman-Lord/Allied Chemical, the magnesium oxide, and the activated charcoal processes which regenerate SO_2 and convert it to a by-product are in general not recommended for Navy bases, because of the complexity of the processes, their high cost in small scale, their need for premium fuel (gas), and problems in marketing or disposing of small amounts of by-product sulfur.

1.3 SITE SPECIFIC STUDIES

1.3.1 Installations Considered

Information gathering, site visits, and analyses were conducted for the following five FGD installations:

- The Chiyoda CT-121 installation at Gulf Power Company's Scholz Station in Sneads, Florida, near Tallahassee
- The Research-Cottrell/Bahco lime/limestone scrubber installation at Rickenbacker AFB, Columbus, Ohio
- The Wellman-Lord/Allied Chemical scrubbing system at Northern Indiana Public Service Company's Mitchell Station in Gary, Indiana
- The A. D. Little soda liquor scrubbing system at the General Motors plant in St. Louis, Missouri
- The FMC concentrated double alkali pilot plant at Firestone Corporation's Pottstown, Pennsylvania plant

1.3.2 Information Gathering During Site Studies

Information gathering goals at each installation included:

- General data on owner, process, and installation
- Capital and operating costs
- Failure modes and associated frequencies of occurrence and times to repair
- General operating history of the facility

1.3.3 Reliability and Maintainability Analyses

The following analyses were carried out for each installation using failure information gathered during site visits:

- A tabulation of failure modes and frequencies was prepared
- A reliability block diagram was prepared. In this diagram, all modules are in series with each other if the failure of any one causes shutdown of the whole system. A module with a backup system is drawn in parallel with its backup system
- The probability of the FGD system operating for one month without failure was calculated
- The probability of a repair crew making a repair within 8 hours was calculated
- The availability was calculated

1.3.4 Reliability Findings

Bechtel experience indicates that any of the current FGD technologies can be made equally reliable if they are designed properly.

The site studies did identify installations at three of the facilities which have experienced high reliability. These were the following:

- Research-Cottrell/Bahco — Rickenbacker AFB — lime/limestone
- General Motors — St. Louis — soda liquor
- Chiyoda CT-121 — Scholz Station — limestone

Table 1-3 provides a comparison of reliability parameters for the Rickenbacker and St. Louis installations. The Electric Power Research Institute (EPRI) has recently announced its evaluation of the Chiyoda CT-121 tests conducted in 1978 and 1979, and confirms the high reliability findings of this study for the CT-121.

Table 1-3

RELIABILITY AND MAINTAINABILITY OF TWO RELIABLE FGD INSTALLATIONS VISITED

Reliability Parameter	Rickenbacker AFB R-C/BAHCO Lime/Limestone	General Motors St. Louis A.D. Little Soda Liquor
Expected Number of Forced Shutdowns per Month	2.4	1.6
MTBF, Mean Time Between Forced Shutdowns, in Hours	515	450
MTTR, Mean Time to Repair in Forced Shutdowns, in Hours	7	8
Availability = MTBF/(MTBF + MTTR)	.986	.983
Total Monthly Maintenance Hours	70	33
Monthly Maintenance Hours for Forced Shutdowns	10	12
Probability Any Failure Repaired in 8 Hours	.99	.96

1.3.5 Designs Recommended

In the light of its previous operating record in the U.S., the Research-Cottrell/Bahco scrubber is a prime candidate for Navy bases where the associated solid waste disposal can be accommodated. If additional information confirms the preliminary findings on the Chiyoda CT-121, it may also be recommended for similar circumstances. The sodium hydroxide scrubber is preferred where environmental permits can be obtained for disposal of liquid wastes.

1.4 LIST OF U.S. INDUSTRIAL SCRUBBERS

A list of 16 operational flue gas desulfurization systems for coal-fired industrial boilers was prepared. Nine technologies are represented. The table lists data on owner, location, vendor, capacity, startup date, service years, reliability, costs, coal sulfur level, percent SO_2 removal, and numbers of boilers and scrubbers.

1.5 STRUCTURE OF THIS REPORT

Section 2 of this report presents the background and basis for the study. The scope of the work is summarized, and then technical and economic assumptions are described.

Sections 3 to 8 provide descriptions and comparisons of the six technologies considered current. Section 3 gives process descriptions, flow diagrams, annual flows, staffings, and waste disposal designs for the technologies. Section 4 presents capital, annual operating, and life-cycle cost comparisons. Sections 5, 6, 7, and 8 give brief comparisons of the current technologies discussing efficiency, operability, reliability, and maintainability.

Section 9 concludes the Task A technology comparisons with descriptions of future FGD technologies.

Sections 10 to 15 report the results of the site specific studies under Task B. Section 10 provides general preliminary remarks and gives details

of the reliability methodology. Sections 11 to 15 provide case-by-case descriptions and reliability analyses of the five installations studied.

Section 16 is a list of FGD installations for coal-fired industrial boilers.

Section 2

BACKGROUND AND BASIS

2.1 BACKGROUND

This document reports results of work performed under Phase IV of the "Navy Energy Guidance Study," contract N68305-77-C-0003, for the Civil Engineering Laboratory at the Naval Construction Battalion Center at Port Hueneme, California. The Phase IV study is entitled "Flue Gas Desulfurization System Application Study." Work on Phase IV was initiated on May 30, 1979. References 1 and 2 describe the work under Phases I, II, and III.

The objective of Phase IV is to examine the availability, costs, and operating performance of industrial-sized, coal-fired boiler flue gas desulfurization (FGD) installations, using generic overview analyses and also site specific studies. The results are intended to assist the Navy in deciding whether to include FGD systems in the coal-fired steam plants being planned.

An enormous amount of effort has gone into the analysis of FGD systems for large power boilers by the utility industry. This analysis has shown that the practicality and relative costs of large-scale FGD systems are quite site sensitive and they will be even more so for small boilers. A large plot area is required for particulate and FGD sludge or by-product storage and disposal systems. When all factors are weighed, some systems will not be practical for the small boilers considered in this study. A typical example is any of the recovery processes, all of which require scarce premium fuels or the uneconomic production of sulfuric acid.

2.2 SCOPE OF WORK

The study required performance of three tasks to determine the feasibility of flue gas desulfurization for coal-fired, industrial-sized boilers at Navy bases. Task A was an overview study to compare economics and performance of selected available technologies over a specified range of sizes. Task B was a site specific study of five existing small FGD installations. Task C involved preparation of a list of operational FGD installations for coal-fired industrial boilers or heaters.

2.2.1 Task A — Evaluation of Technologies in General

Bechtel has made cost approximations and ranked performance of six FGD technologies in commercial use:

- Lime
- Limestone
- Double alkali
- Soda liquor producing solid wastes
- Soda liquor producing liquid wastes
- Sodium Sulfite — Bisulfite (Wellman-Lord/Allied Chemical)

Capital, operating, and life-cycle costs were prepared at load factors of 25 and 50 percent for the five current technologies for boiler installations of the following sizes (in Btus of heat transferred into steam):

- 400 x 10^6 Btu per hour
- 200 x 10^6 Btu per hour
- 100 x 10^6 Btu per hour
- 50 x 10^6 Btu per hour
- 25 x 10^6 Btu per hour

Also, these commercial technologies were ranked for efficiency, operability, reliability, and maintainability.

In addition, Bechtel examined activated charcoal absorption and five other technologies judged to be promising but not yet fully demonstrated in industrial-sized installations in the United States.

2.2.2 Task B — Site Specific Studies of Industrial Scrubbers

Data-gathering activities including site visits were conducted for five installations representing the five current technologies and one promising future technology.

The sites visited and technologies represented are shown in Table 2-1.

Note that the Rickenbacker installation is adaptable to both lime and limestone wet scrubbing. The Rickenbacker installation was the first industrial-sized FGD installation in the United States used for both alkalis.

The NIPSCO installation has a capacity exceeding the industrial-sized range (its capacity is approximately 1000 x 10^6 Btu per hour of steam output). The facility was visited, however, because it is the earliest U.S. installation applying the Wellman-Lord/Allied Chemical technology to a coal-fired boiler.

The example of future technology was the Chiyoda jet bubbling limestone slurry scrubber operating at Gulf Power's Scholz Station power plant in Florida. This proprietary system has been the subject of great interest by the Electric Power Research Institute (EPRI); it was decided to visit the installation even though its operating period has been only approximately nine months.

Table 2-1

FGD INSTALLATIONS VISITED

Installation, Owner/Operator	Location	10^3 SCFM* Design Flue Gas Capacity	Control Process	Vendor
Rickenbacker Air Force Base	Columbus, Ohio	55,000	Lime Wet Scrubbing Limestone Wet Scrubbing	Research-Cottrell (Bahco)
Firestone Tire & Rubber Co.	Pottstown, Pennsylvania	8,070	Double Alkali (Concentrated)	FMC Environmental Equipment
General Motors Corp.	St. Louis, Missouri	93,000	Soda Liquor Wet Scrubbing	A.D. Little
Northern Indiana Public Service Company (NIPSCO) Mitchell Station	Gary, Indiana	320,000	Sodium Sulfite-Bisulfite (Wellman-Lord/ Allied Chemical)	Davy McKee Corporation and Allied Chemical
Gulf Power Co. Scholz Station	Tallahassee, Florida	53,000	Limestone Jet Bubbling	Chiyoda

*SCFM = Standard cubic feet per minute (at 60°F and one atmosphere); see Table 2-2

Data-gathering goals at each installation included getting data on general and operating history as well as information for reliability and maintainability analysis. General data objectives included:

- Location
- Owner/Operator
- Manufacturer
- Capacity
- Type of process
- Owner objectives
- Regulatory criteria for particulate and SO_2 emissions
- Fuel cost savings through use of the scrubber
- Source of financing
- Power requirement
- SO_2 removal efficiency
- Type of coal and coal sulfur content
- Sorbent consumption rate and percent utilized
- Sensitivity to particulate loading
- Effluent disposal
- Design life
- Length of service
- Date of installation
- Personnel requirements

- Capital cost
- Operating cost
- Operating labor cost
- Maintenance cost
- Maintenance labor cost
- Materials cost
- Electricity cost
- Operating or design problems
- Solutions to problems
- Types of malfunction
- Downtime

Information sought on reliability and maintainability included:

- Mean Time Between Failures (MTBF)
- Mean Time To Repair (MTTR)
- Preventive/scheduled maintenance
- Failure Mode and Effects Analysis (FMEA)
- Critical items list
- Reliability block diagram
- Availability (A)
- Operational life profile
- Special training requirement
- Supply problems

Reference 3 gives definitions of the above items. The next seven paragraphs summarize some of these definitions.

The Mean Time Between Failures (MTBF) of components and overall systems are computed from failure occurrence data during normal operations. Failure times are assumed to be exponentially distributed.

The Mean Time To Repair (MTTR) is computed from repair time data from normal operation. Repair time includes the time required to bring the system back into operation once a repair crew is assigned, assuming parts, tools, and instruction manuals are on hand. Repair time does not include delays associated with deciding to repair, assigning the work crew, or obtaining required materials.

A Failure Mode and Effects Analysis (FMEA) is a tabulation of component failure data showing the effect on the overall system of component failures of various types.

Critical items are short-life (generally inexpensive) items like drive belts and instrument probes which must be kept on hand because of uncertainty of supply.

A reliability block diagram shows which components are in series and which are in parallel (redundant) in the overall system. The reliability block diagram is used to compute overall system reliability from tested reliabilities of components.

Availability A is defined as:

$$A = \text{uptime}/(\text{uptime} + \text{downtime}) \qquad (2\text{-}1)$$

The value for the availability will vary with differing definitions of uptime and downtime. The full definitions used in this study for reliability, maintainability, and availability are given in this section.

An operational life profile sets forth extreme conditions and stresses encountered by a system over its operating life.

2.2.3 Task C — List of Industrial-sized FGD Installations

A list was prepared of operational FGD systems for coal-fired boiler installations in the United States with plant sizes up to 500 x 10^6 Btu per hour of coal input. Data objectives for each installation included:

- Location
- Owner/Operator
- Manufacturer
- Capacity
- Type of process
- Capital cost
- Operating cost
- Payback period
- Date of installation
- Length of service
- Design life
- Downtime
- SO_2 removal efficiency
- Percent sulfur in coal

2.3 TECHNICAL BASIS FOR THE STUDY

2.3.1 Coal

The flue gas flows and boiler rating for Task A cost estimates were computed assuming the following coal is utilized in the boiler plants requiring FGD systems:

	Weight Percent
— Sulfur (Average)	3.39
— Ash	16.50
— Carbon	53.81
— Hydrogen	4.00
— Nitrogen	1.08
— Oxygen	8.64
— Moisture	12.58
	100.00

The coal is an Illinois Number 6 bituminous coal from Macoupin County, Illinois. It has a heating value of 9860 Btu per pound and an assumed maximum sulfur level of 4.75 percent. The maximum sulfur level is used for equipment sizing. The average value is used in computing annual flows.

2.3.2 Boiler Plant Configuration

For the cost comparisons in Task A, the FGD system is assumed to be part of a boiler plant which also includes one or more coal-fired stoker boilers, a particulate removal system, and a chimney. The boiler plant may be new, or the FGD system may be retrofitted to an existing boiler plant. In either case, adequate land for the FGD system is assumed available.

The choice of the particulate removal systems has been to some extent arbitrary. In this study, it is assumed to be baghouses. Baghouse fabric filters offer high efficiency particulate removal.

Their capital costs in many cases compare favorably with those of electrostatic precipitators for comparable fly ash removal efficiencies. Available baghouse filter life data are insufficient for in-depth evaluation. Nevertheless, there appears to be a trend toward using baghouses as the particulate removal system in new large-scale power plant designs.

The flue gas entering the FGD system is assumed to contain 60 percent excess air, which includes the excess air fired to the boiler plus air leaked into the flue gas through fan casings, equipment, and ducting between the boiler and the FGD scrubber inlet. The flue gas is assumed to enter the FGD system at 300°F and one atmosphere pressure.

A steam-flue gas heat exchanger providing 50°F of reheat is assumed integral to each FGD system.

A chimney conveys the treated flue gas to the atmosphere. Although the FGD systems include gas reheaters, special measures may be necessary to protect the chimney interior surface from corrosion caused by condensed water vapor containing dissolved SO_2. These measures are not considered here.

Capital and operating costs in this study apply to the FGD systems alone. Boilers, particulate removal systems,* and chimneys are not included in the costs presented.

Permanent disposal of wastes from the FGD systems is assumed to be handled by a contractor paid on an annual basis. Accordingly, no capital costs are assumed for a waste disposal site.

The subsystems within each FGD system studied include:

- Gas supply ducting
- Presaturator chamber
- Booster fan
- Air blower for forced oxidation where applicable

---

*Note: The spray dry/baghouse technology considered in Section 9 has a fabric filter downstream rather than upstream of the main FGD scrubber, and the gas does not require reheat. Cost credits for these features must be considered when comparing capital costs of this process.

- The SO_2 absorber
- The scrubbing liquor or slurry preparation and circulation system
- Spent-absorbent processing, waste treatment, waste solid handling, and temporary storage system
- Sulfur by-product recovery system (where applicable)
- Reheat-heat exchanger

2.3.3 Ratings and Efficiencies

Table 2-2 shows the ways of designating boiler and FGD plant capacity which are considered nominally equivalent throughout this report.

The entries in Table 2-2 are based on the following approximate conversion relations:

- Each ton of coal has a heat content of 20 x 10^6 Btu (or 10,000 Btu per pound)
- The boiler efficiency is 80 percent. This is the percent of coal heat content that is transferred into steam energy.
- For each pound of steam generated, 1000 Btu of heat must be transferred into the steam system by the boiler
- Each 10,000 Btu of coal heat can produce one kilowatt-hour of electricity in an efficient utility power plant (this is called the "heat rate"). One megawatt is 10^3 kilowatts*
- Each 10^6 Btu per hour coal heat produces 400 actual cubic feet per minute (ACFM) of flue gas at 300°F and one atmosphere, when 60 percent excess air is used for combustion and allowance for inleakage
- Each 10^6 Btu per hour of coal heat produces 300 standard cubic feet per minute (SCFM) of flue gas. A standard cubic foot is measured at 60°F and one atmosphere

*Because scrubbers were first introduced at large power generation facilities, scrubber sizes are often referred to in terms of the megawatts of the power plants they serve.

Table 2-2

EQUIVALENT DESIGNATIONS OF BOILER AND FGD CAPACITY

Transfer of heat = boiler heat output, 10^6 Btu/hr	400	200	100	50	25
Production of steam, 10^3 lb/hr	400	200	100	50	25
Consumption of fuel, 10^6 Btu/hr	500	250	125	62	31
Consumption of fuel, tons/hr	24	12	6	3	1.5
Equivalent power plant rating, MWe	50	25	12.5	6.2	3.1
Flue gas volume flow at 300°F and one atmosphere, 10^3 actual cubic feet per minute (10^3 ACFM)	200	100	50	25	12
Flue gas volume flow at 60°F and one atmosphere, 10^3 standard cubic feet per minute (10^3 SCFM)	150	75	38	19	9

The most natural units for expressing scrubber capacities are units of volumetric flow of flue gas entering the FGD system (ACFM).

An excess air value of 60 percent was selected as typical of stoker coal boilers common in industrial installations.

Unless otherwise noted all capacities stated in 10^6 Btu per hour in this report refer to heat transferred into the steam system by the boiler.

2.3.4 Load Factor

Boiler plant annual load factors of 50 percent and 25 percent are considered in this study, where:

$$\left(\begin{array}{c}\text{Load}\\\text{Factor}\end{array}\right) = \left(\frac{\text{Annual average steam demand}}{\text{Maximum design steam demand}}\right)$$

Site surveys in Reference 4 suggest that a 33 percent load factor is typical for Navy bases.

Load factors are in the range of 25 to 50 percent (rather than 75 to 90 percent as in continuous process plants) because at Navy bases the main mission of the boiler plants is to provide steam for heating office, living, and work spaces. The full boiler capacity may be required only 54 hours* during an entire year.

2.3.5 Environmental Standards

It is assumed that FGD systems will be required for all boilers in the size range studied in Task A, and that the FGD systems will be required to remove 90 percent of the SO_2 emitted during a 30-day period as a result of burning

*Navy base heating systems are usually designed to provide adequate heating for all but 2.5 percent of the time (54 hours) during the three consecutive coldest months of the year.

the type of coal discussed in paragraph 2.3.2 above. Annual cost calculations in Section 4 assume 90 percent removal.

Currently, state and local regulations require FGD systems in certain localities, especially non-attainment areas.

At this time, there are no Environmental Protection Agency (EPA) SO_2 emission standards applying to new boilers installed at Navy bases. Since Navy base boiler plants do not generate electricity for sale beyond base limits, they are excluded from coverage by the June 1979 New Source Performance Standards (NSPS) for electric utility steam generating units promulgated by EPA.

EPA is currently preparing for new industrial boilers that would apply to Navy bases. EPA expects to announce the draft of these standards in October 1980. The final form of such standards is a matter of speculation. It is assumed that they will require levels of SO_2 removal similar to those in force for electric utility FGD systems.

Figure 2-1 shows how the SO_2 New Source Performance Standards for electric utility boilers vary with the percent of sulfur in the coal. For the high-sulfur coal selected in this study, the SO_2 removal requirement for an electric utility would be 90 percent. The processes considered have been cited by EPA as capable of supporting such standards.

Under the electric utility NSPS, a 30-day rolling average is used to determine compliance with the removal requirement. This means that if 90 percent is the removal level required, the FGD system must remove 90 percent of the SO_2 generated during any 30-day period. Since some outages of the FGD system are always expected, the FGD system must be designed with a capability of removing more than 90 percent. The current technologies described in Section 3 can meet this removal standard.

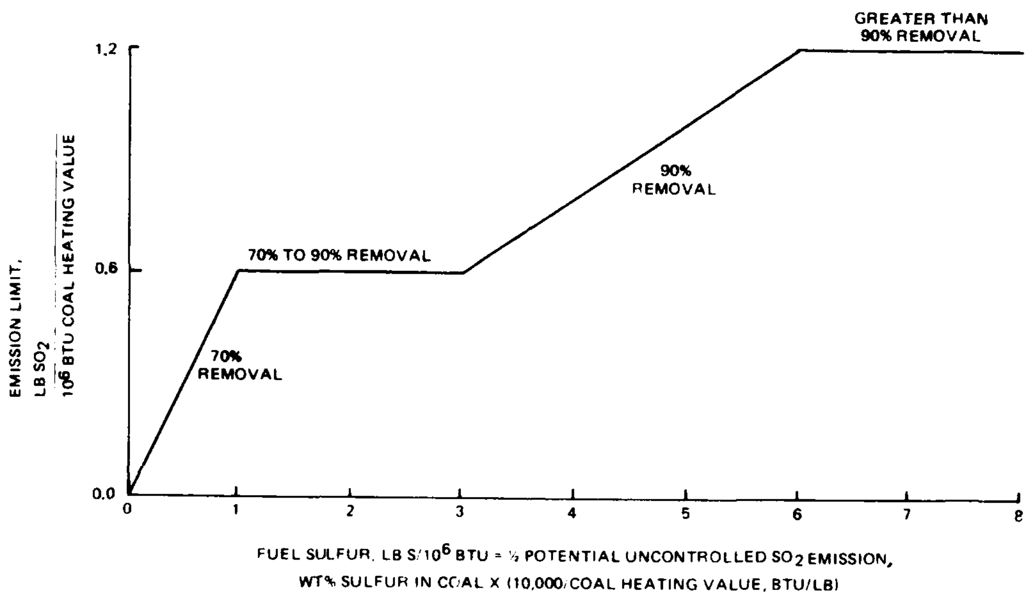


Figure 2-1

SO_2 REMOVAL REQUIREMENTS OF 1979 NEW SOURCE PERFORMANCE STANDARDS

2.3.6 Equipment Redundancy

For this study it has been assumed that boiler plants with heat outputs of 200 and 400 x 10^6 Btu per hour will be equipped with two 60 percent capacity scrubbers. Because demand exceeds 60 percent of rated capacity only a small fraction of a year, during most of the year the idle scrubber will qualify as a spare.

For boiler plants with capacities of 25, 50 and 100 x 10^6 Btu per hour, it has been assumed that a single 100 percent capacity scrubber will be adequate.

2.3.7 Reliability

In this study, *reliability* of a complete FGD system or a component is defined as the probability that the system will perform continuously for one month without a malfunction forcing shutdown, where "to perform" is defined as the removal of at least 90 percent of the sulfur entering with the coal. This definition agrees with a common mathematical definition of reliability.

For ranking technologies in this study, however, the probability defined above is taken as a measure of "operability" or ease of operation.

For ranking the technologies under the heading "reliability" in this study, the measure used is the inherent availability defined below.

2.3.8 Maintainability

Maintainability is defined in this study as the probability that an assigned repair crew can correct a significant malfunction within one 8-hour work period.

It is assumed that the work crew has appropriate tools, parts, and instruction manuals.

2.3.9 Availability

The *availability*, A, is defined as

$$A = \frac{\text{operating hours}}{\text{operating hours + maintenance hours}} \qquad (2\text{-}2)$$

where the maintenance hours are those to correct failures which require FGD system shutdown.

2.4 COST BASIS FOR THE STUDY

Capital and operating costs used in this study are based on vendor quotes and Bechtel design and construction experience with FGD systems. Certain cost assumptions are presented in the remainder of this section. Additional details are given in Section 4.

2.4.1 Wage and Price Level

The wages and prices used for costs in Section 4 are second quarter 1978 wages and prices.

2.4.2 Capital Costs

Capital costs are computed assuming labor productivity at an average Midwest United States location and an average labor rate of $13 per hour.

Bechtel's method of capital cost estimation is described in Section 4.

2.4.3 Operating Costs

Operating labor costs are computed by multiplying $20 per hour times the hours worked by the operating force. The $20 includes overhead and other allowances above an $8 per hour base wage, as explained in Section 4.

The following typical prices have been used for utilities and scrubber chemicals:

- Limestone (94 percent pure) at \$10/ton
- Lime (85 percent pure) at \$50/ton
- Soda ash at \$70/ton
- Natural gas at \$2.40/10^6 Btu input
- Electric power at \$0.033/kilowatt-hour
- Steam at \$5.32/10^3 pounds output*
- Water at \$0.35/10^3 gallons

In this study, no by-product credit is assigned for sulfur produced by regenerable processes. It is assumed that marketing costs will equal revenues from sale of the sulfur.

The methodology used for operating materials and maintenance costs is described in Section 4.

2.4.4 Life-Cycle Costs — U.S. Navy Methodology

The Navy's methodology for computing life-cycle costs in Reference [illegible] has been used. A short description of that methodology is given in Appendix A. Present values are computed for each project year as a product of costs at the zero of time and a discount factor based on a discount rate that is 10 percent after general inflation has been removed. Thus, the discount rate is equivalent to a private-sector 18 percent capital charge in periods when the general inflation rate is 8 percent.

---

*A value of \$5.32/10^3 pounds of steam is a levelized cost computed from the data of Reference 2 as the cost of steam from a 200 x 10^6 Btu/hr central steam plant operating at a load factor of 100 percent using coal at \$1.41/10^6 Btu.

Energy costs are anticipated to rise faster than general inflation. Annual inflation rates taken from Reference 6 are shown in Table 2-3.

Table 2-3

ASSUMED ANNUAL INFLATION RATES

Commodity	Short Term Total Inflation Rate	Long Term Differential Inflation Rate
Labor and Materials	8.3%	0%
Coal	10%	+5%
Natural Gas	16%	+10%
Electricity	16%	+6%

The differential inflation rate is the difference between the rate of inflation for the item considered and the general inflation rate for labor and materials. The introduction of differential inflation leads to special discount factors given in Reference 5 and reproduced for convenience in Appendix C. The tables in Appendix C give discount factors for each single year of project life. They also give cumulative uniform series discount for costs which recur for several years.

The zero of time for this study is assumed to be May 1978. All scrubber systems are assumed to start up in May 1981 and to operate for 25 years. Scrubber plant construction is assumed to begin in May 1979 and last 24 months for systems with a capacity of 400×10^6 Btu per hour. It begins in 1980 and lasts 12 months for systems with capacities between 25 and 200×10^6 Btu per hour.

Table 2-4 shows the pattern for calculations of present values presented in Sections 4 and 9. The discount factors for years 4 to 28 in Table 2-4

Table 2-4

PRESENT VALUE CALCULATION PATTERN

Cost Item	Differential Inflation Rate %	Project Year	Amount* One Time	Amount* Recurring	Discount Factor	Present Values*
1st Year Construction	+ 0	2	2,443		0.867	2,118
2nd Year Construction	+ 0	3	4,887		0.788	3,851
Total Investment			7,330		--	5,969
Electricity	+ 6	4-28		67	14.588	977
Gas (for sulfur Reduction)	+10	4-28		--	25.000	
All Other Annual Cost	+ 0	4-28		1,542	7.156	11,035
Total Annual Cost				1,609		12,012
Total Project Present Value ($1000s)						17,981
Total Heat Loads Over 25 Years, 10^9 Btu						43,800
Unit Energy Present Value, $/$10^6$ Btu						0.41
Levelized Unit Energy Costs (in 1979 Dollars), $/$10^6$ Btu						1.[illegible]5

*One time and recurring amounts and present values are in thousands of second quarter 1978 dollars.

are derived in Table A-1. The single year factors are taken directly from Appendix C. For systems with 12-month construction periods, all construction costs would appear in the third project year. Table 2-4 is presented again in Section 4 as Table 4-8.

The unit present values presented in this report assume operations beginning in the fourth project year. They are lower than the standard unit present values used by the Naval Facilities Engineering Command (NAVFAC), which have operations beginning the first project year. To convert unit present values in this report to the NAVFAC form, multiply by 1.33309. This factor is derived in Appendix A. Thus, the $0.41 per million Btu unit present value in Table 2-4 would be $0.547 per million Btu in NAVFAC form.

Levelized unit energy cost calculations are described in Reference 7. Levelized costs have the "feel" of private sector dollars per million Btu costs, but have energy contributions augmented to take into account differential inflation. Levelized costs are described in Appendix B. There the 1978 levelized costs for the case in Table 2-4 is shown to be $1.55 per million Btu. To get 1978 levelized costs from unit present values in this report, multiply by 3.49. In this report, 1979 levelized costs are reported. These are obtained from 1978 levelized costs merely by multiplying by a one year short-term total inflation factor for labor and materials of 1.083 suggested by Table 2-3. Thus 1979 levelized costs can be derived from 1978 unit present values by multiplying by a single combined factor of $(3.49)\cdot(1.083) = 3.780$.

Section 3

CURRENT TECHNOLOGIES

3.1 INTRODUCTION

In this and the following five sections of this report, six FGD technologies that have been demonstrated in the United States are evaluated to determine their suitability for Navy bases. These processes include:

- Limestone slurry
- Lime slurry
- Double alkali (concentrated mode)
- Soda liquor with solid crystal waste disposal
- Soda liquor with liquid waste disposal
- Wellman-Lord/Allied Chemical

The first five are "throwaway" processes. This means that the sulfur removed from the flue gas leaves solid or sludge as a waste product that must be disposed of. The sixth process converts the removed SO_2 to solid sulfur, a salable product. All six are wet scrubbing processes.

In this section, the five processes are first described. Then the annual material and utility requirements, manpower requirements, and waste disposal requirements are discussed.

In Sections 4 through 8, these processes are compared on the basis of cost, efficiency, operability, reliability, and maintainability.

3.2 PROCESS DESCRIPTIONS

3.2.1 Limestone Slurry Process

The absorption of SO_2 from flue gases by a limestone slurry involves the reaction of SO_2 with limestone ($CaCO_3$) to form calcium sulfite ($CaSO_3$) with some oxidation of the sulfite to form calcium sulfate ($CaSO_4$). The overall reactions can be represented as follows:

$$SO_2 + CaCO_3 + \tfrac{1}{2}H_2O \rightarrow CaSO_3 \cdot \tfrac{1}{2}H_2O + CO_2$$

$$SO_2 + \tfrac{1}{2}O_2 + CaCO_3 + 2H_2O \rightarrow CaSO_4 \cdot 2H_2O + CO_2$$

The SO_2 is absorbed during a short residence time contact of gas and absorbent slurry. A reaction vessel or hold tank provides the necessary residence time for dissolution of the alkaline absorbent and for precipitation of the calcium sulfite and sulfate crystals. The hold tank effluent is recycled to the scrubber to absorb additional SO_2. A slip stream from the hold tank is sent to a thickener to remove the precipitated solids from the system. The sludge stream produced by the thickener is dewatered, blended with fly ash and lime, and trucked to landfill. Figure 3-1 is a simplified flow diagram of the limestone slurry process.

In slurry preparation, limestone (delivered by truck and stored in an uncovered reserve storage pile and a short-term storage bin) is ground in wet ball mills and diluted with recycled process wastewater to produce slurry for makeup to the absorption section. It may be more suitable for the Navy to purchase ground limestone for smaller boilers.

In SO_2 absorption, flue gas discharging from an induced draft fan is adiabatically cooled and saturated by slurry sprays located in especially designed duct sections (presaturators) just upstream of the absorber. Flue gas enters the absorber near the bottom and rises countercurrent to absorbent slurry which is sprayed downward through banks of nozzles located near the top of the absorbers. Entrained slurry droplets are removed from

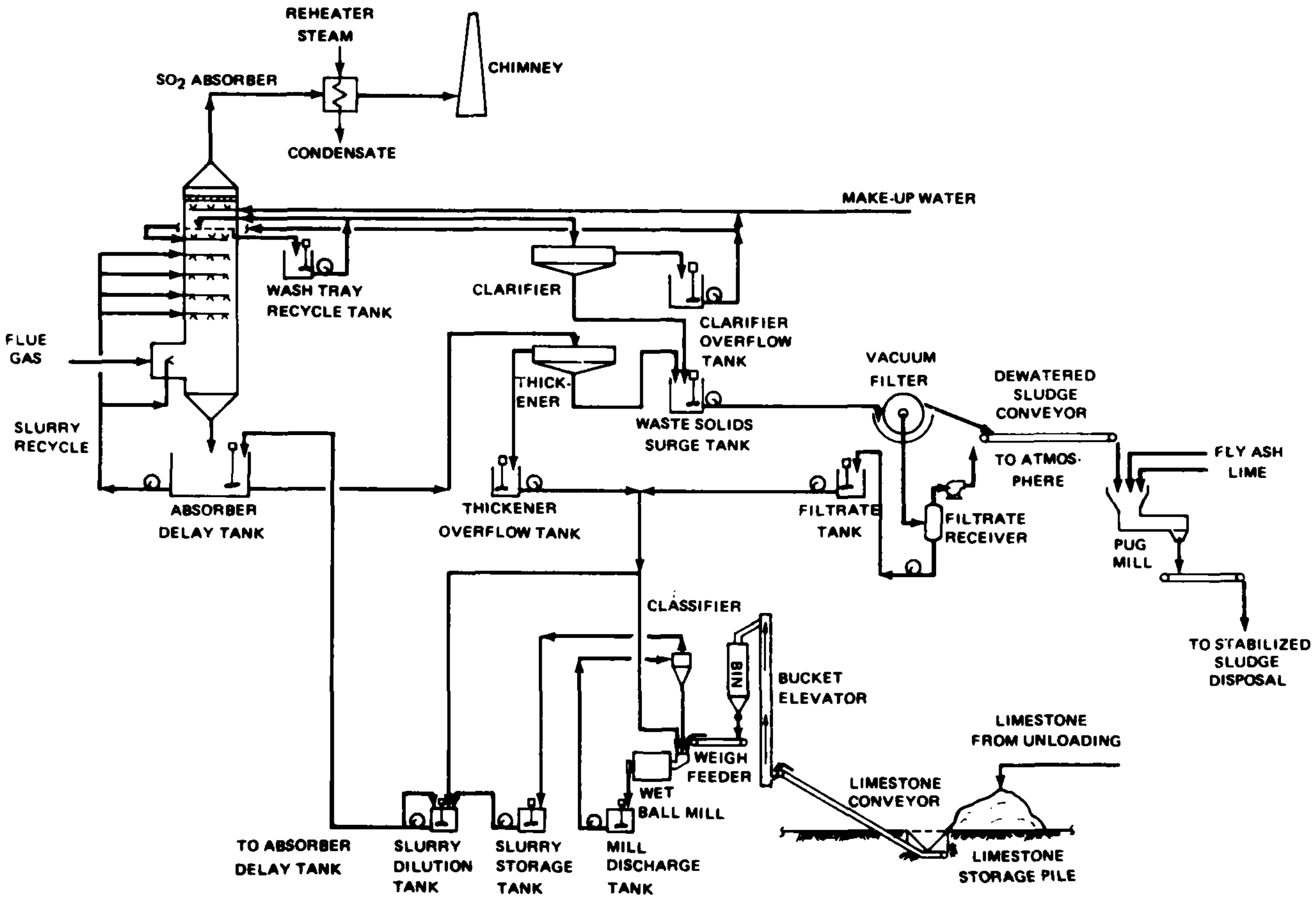


Figure 3-1
LIMESTONE SLURRY PROCESS FLOW DIAGRAM

the flue gas by a wash tray system and chevron mist eliminators. Solids captured in the absorber wash trays are separated from the tray water stream, and the clarified water is returned to the wash trays. Makeup water is added through the mist eliminator wash sprays. The flue gas leaving the absorbers is reheated before entering the chimney.

Processing of a slipstream of the slurry begins when it is discharged into a reaction vessel where crystallization of some of the calcium salts takes place. Rubber-lined constant-speed pumps recirculate the slurry to the absorber and presaturator spray nozzles. Limestone slurry makeup is added to the reaction vessel to maintain a stoichiometric ratio of 1.3 based on sulfur removed. Concentration of absorbent slurry solids is maintained at 15 weight percent by variation of the spent-absorbent withdrawal rate. The spent absorbent is pumped to a thickener for solids concentration. Clarified liquor overflows from the thickener and is returned to the reaction vessels. Thickener underflow is pumped from a surge tank to a rotary vacuum filter system. Filtrate is returned to the limestone slurry preparation area. The filter cake containing about 50 weight percent solids is discharged by conveyor to the waste sludge stabilization system. There it is presumed to be mixed in a pug mill with fly ash from the boiler particulate removal system. Dry lime is added for stabilization at the rate of 2 weight percent of the combined weight of dewatered sludge and dry fly ash.

3.2.2 Lime Slurry Process

The lime slurry process is very similar to the limestone slurry process in process chemistry and equipment design. The overall reactions occurring in the lime slurry process are:

$$SO_2 + CaO + \tfrac{1}{2}H_2O \rightarrow CaSO_3 \cdot \tfrac{1}{2}H_2O$$

$$SO_2 + \tfrac{1}{2}O_2 + CaO + 2H_2O \rightarrow CaSO_4 \cdot 2H_2O$$

Figure 3-2 is a simplified flow diagram of the lime slurry process.

Pebble lime is delivered by covered truck and unloaded pneumatically into storage silos. Lime is slaked with makeup water, diluted with recycled process water, and stored for use as absorbent makeup. All material handling rates and storage volumes are smaller than the corresponding values for the limestone slurry system because of the lower alkali molecular weight, higher reactivity, and reduced stoichiometric ratio associated with the lime slurry process (1.1 versus 1.3 for limestone).

The SO_2 absorption section for the lime slurry process is identical to that for the limestone slurry system, except that the absorbent recycle slurry pumping system is sized for the lower liquid-to-gas ratio (L/G) permitted by the more reactive lime absorbent. Flue gas reheat requirements are the same as for the limestone slurry system.

Slurry handling, concentration, and waste product stabilization sections are similar to, but smaller than, the corresponding sections of the limestone slurry system. The absorbent slurry makeup system is sized to handle the smaller makeup rate associated with the lower molecular weight of lime and stoichiometric ratios, the sludge dewatering equipment is sized for lower sludge production, and the sludge blending and storage equipment is sized for the lower sludge solids production rate.

3.2.3 Double Alkali Process - Concentrated Mode

The double alkali process in U.S. FGD applications utilizes a sodium sulfite solution to absorb SO_2 from flue gas. The spent absorbent is reacted with lime to precipitate calcium sulfite and regenerate the active sodium absorbent. The precipitated calcium salts are separated and dewatered for disposal.

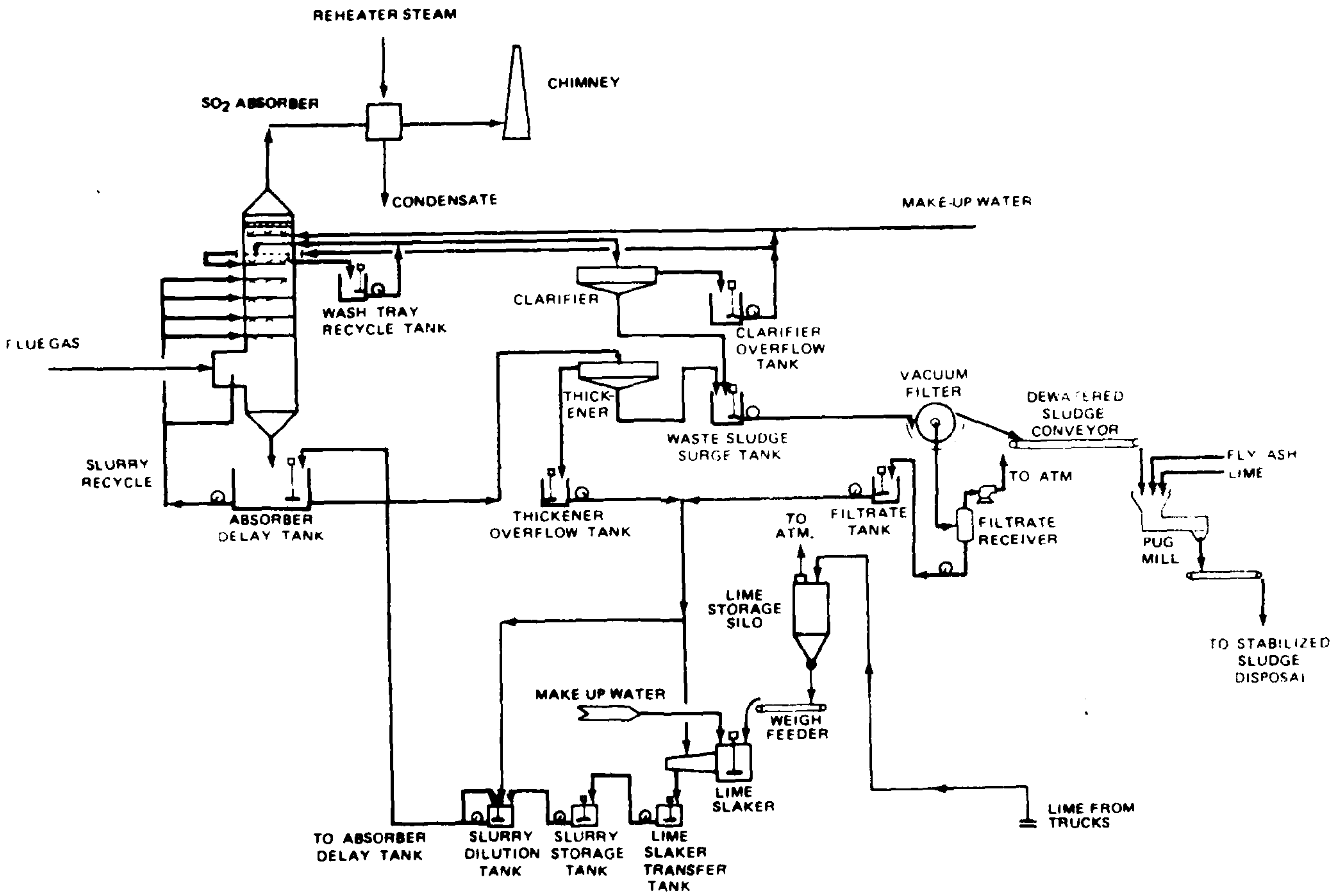


Figure 3-2
LIME SLURRY PROCESS FLOW DIAGRAM

The version of the double alkali process that is simplest and that has been demonstrated for industrial FGD applications is the version known as the concentrated mode process. Figure 3-3 is a simplified flow diagram for this process.

Chemical reactions in the absorber include:

$$Na_2SO_3 + SO_2 + H_2O \rightarrow 2NaHSO_3$$

$$Na_2SO_3 + \frac{1}{2}O_2 \rightarrow Na_2SO_4$$

Chemical reactions in sorbent regeneration include:

$$Ca(OH)_2 + 2NaHSO_3 \rightarrow Na_2SO_3 + CaSO_3 \cdot \frac{1}{2}H_2O + 3/2\ H_2O$$

$$3Ca(OH)_2 + 6NaHSO_3 + 2Na_2SO_4 \rightarrow CaSO_3 \cdot 2CaSO_4 \cdot 4H_2O + 5Na_2SO_3 + 2H_2O$$

In the last equation, the double salt is representative of hydrated compounds formed by the reactions.

The raw material handling system includes equipment for receiving and storing soda ash and dry lime and preparing makeup sodium carbonate solution and lime slurry. Soda ash is conveyed pneumatically from self-unloading delivery trucks to storage silos. Soda ash and recycled process water are fed to a dissolving tank where a 20 percent sodium carbonate absorbent makeup solution is prepared. This solution is fed to the regenerated absorbent liquor storage tank to replace the sodium values lost in the waste sludge filter cake. Dry pebble lime is delivered by truck and conveyed mechanically to a storage bin. The lime is slaked with makeup water and the resulting slurry is transferred to an agitated slurry storage tank from which it is fed to the absorbent regeneration reactor.

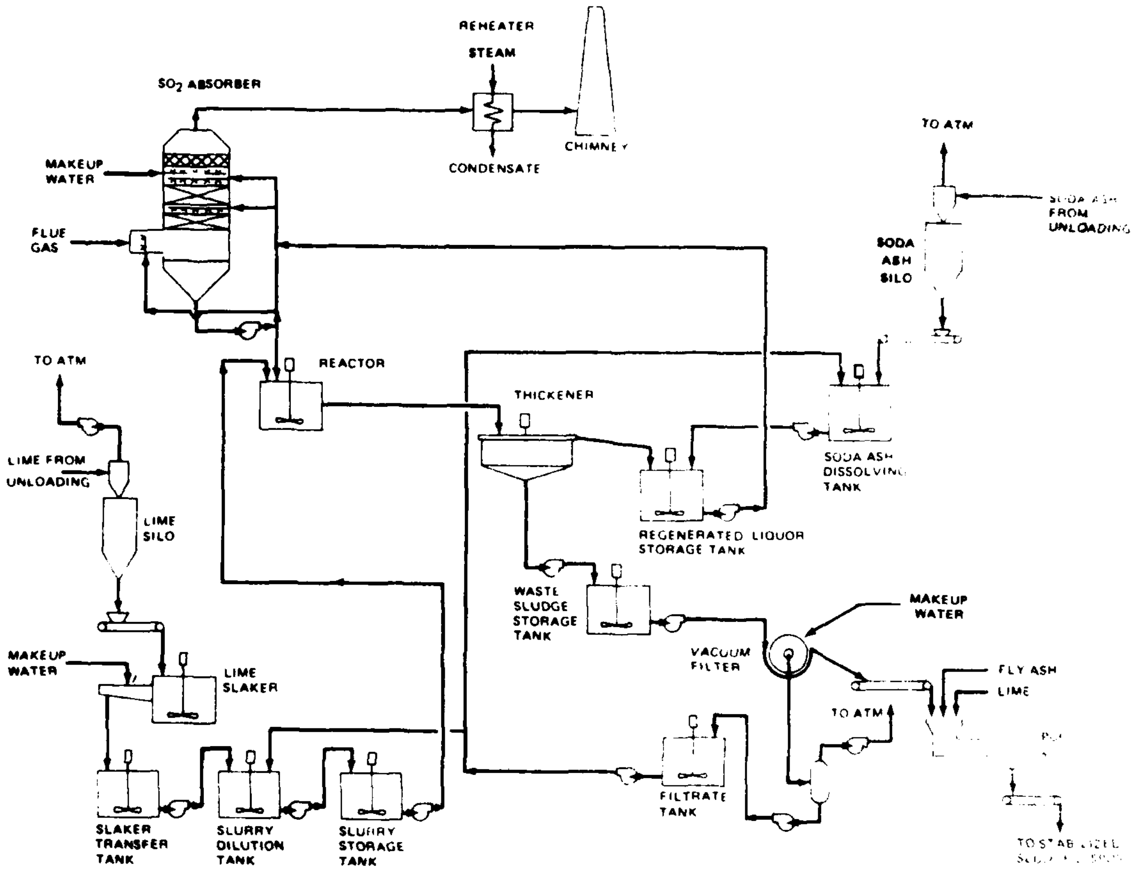


Figure 3-3

SODIUM/LIME DOUBLE ALKALI PROCESS FLOW DIAGRAM

CONCENTRATED MODE

In the absorption section, hot flue gas is first cooled and saturated by absorbent liquor sprays located in specially designed duct sections (pre-saturators) just upstream of the absorber inlet. The cooled, saturated flue gas is contacted with the sodium sulfite absorbent solution in a vertical, countercurrent absorber having two stages of mobile-ball packing for other suitable tower internals to facilitate SO_2 absorption. The cleaned flue gas passes through a chevron mist eliminator for removal of entrained liquor droplets and is then reheated before discharging to the chimney.

In the absorbent regeneration section, the absorber effluent liquor is pumped to the reactor tank where it is mixed with makeup lime slurry. The resulting slurry of calcium salts in regenerated absorbent liquor is pumped to a thickener for separation of the waste solids. The thickener underflow sludge is pumped to a sludge storage tank, then to the sludge dewatering and stabilization section. The clarified liquor overflows from the thickener into a regenerated absorbent storage tank. Makeup sodium carbonate solution is added to the regenerated absorbent to replace sodium lost in the waste sludge cake, and the resulting solution is injected into the absorber recycle liquor system.

In the sludge dewatering and stabilization section, sludge from the waste sludge storage tank is fed to rotary drum vacuum filters where it is further dewatered. During filtration the sludge solids cake is washed with process makeup water to recover the sodium contained in the filter cake surface moisture. The filtrate is collected and pumped back to the regeneration and raw material processing sections for reuse.

3.2.4 Soda Liquor Wet Scrubbing with Solids Waste Disposal

The process described below includes sodium-based clear liquor scrubbing plus a crystallization system to recover waste sulfur-bearing sodium salts in solid form. FGD systems using sodium carbonate or sodium hydroxide as scrubbing reagents produce waste in liquid form. Additional equipment

to produce a solid waste may be required for inland Navy locations where disposal of sodium sulfate solution is prohibited. Figure 3-4 is a flow diagram describing this process.

The soda liquor preparation and absorber sections for this process are similar to those in the double alkali process described above.

In the spent-liquor processing section, a slip stream of absorber effluent liquor is pumped to an oxidizer, then to a chiller-crystallizer which causes precipitation of sulfur-bearing sodium salts (Glauber's salt). The underflow slurry containing these salts is pumped to a thickener for separation of waste solids. The thickener underflow sludge is pumped to a sludge storage tank then to a rotary drum vacuum filter for further dewatering. The cake is then stored for disposal by burial. Clarified liquor streams from the crystallizer and thickener are pumped to the liquor storage tank for reuse in the absorber.

3.2.5 Soda Liquor with Liquid Waste Disposal

In some localities, disposal of liquid soda scrubbing wastes may be permitted by government environment control authorities. In this case, the sodium carbonate system would be simpler and less expensive. Spent liquor processing components in Figure 3-4 could be replaced by a forced oxidation tank and blower, a pH neutralization tank, and a waste liquid storage tank.

3.2.6 Wellman-Lord/Allied Chemical Process

The Wellman-Lord process employs wet absorption of SO_2 from flue gas by reaction with sodium sulfite (Na_2SO_3) to form sodium bisulfite ($NaHSO_3$) and some sodium sulfate (Na_2SO_4). Desulfurized flue gas is reheated and released to the atmosphere. The primary reactions occurring in the absorber are:

$$Na_2SO_3 + H_2O + SO_2 \rightarrow 2NaHSO_3 \quad (1)$$

$$Na_2SO_3 + \tfrac{1}{2}O_2 \rightarrow Na_2SO_4 \quad (2)$$

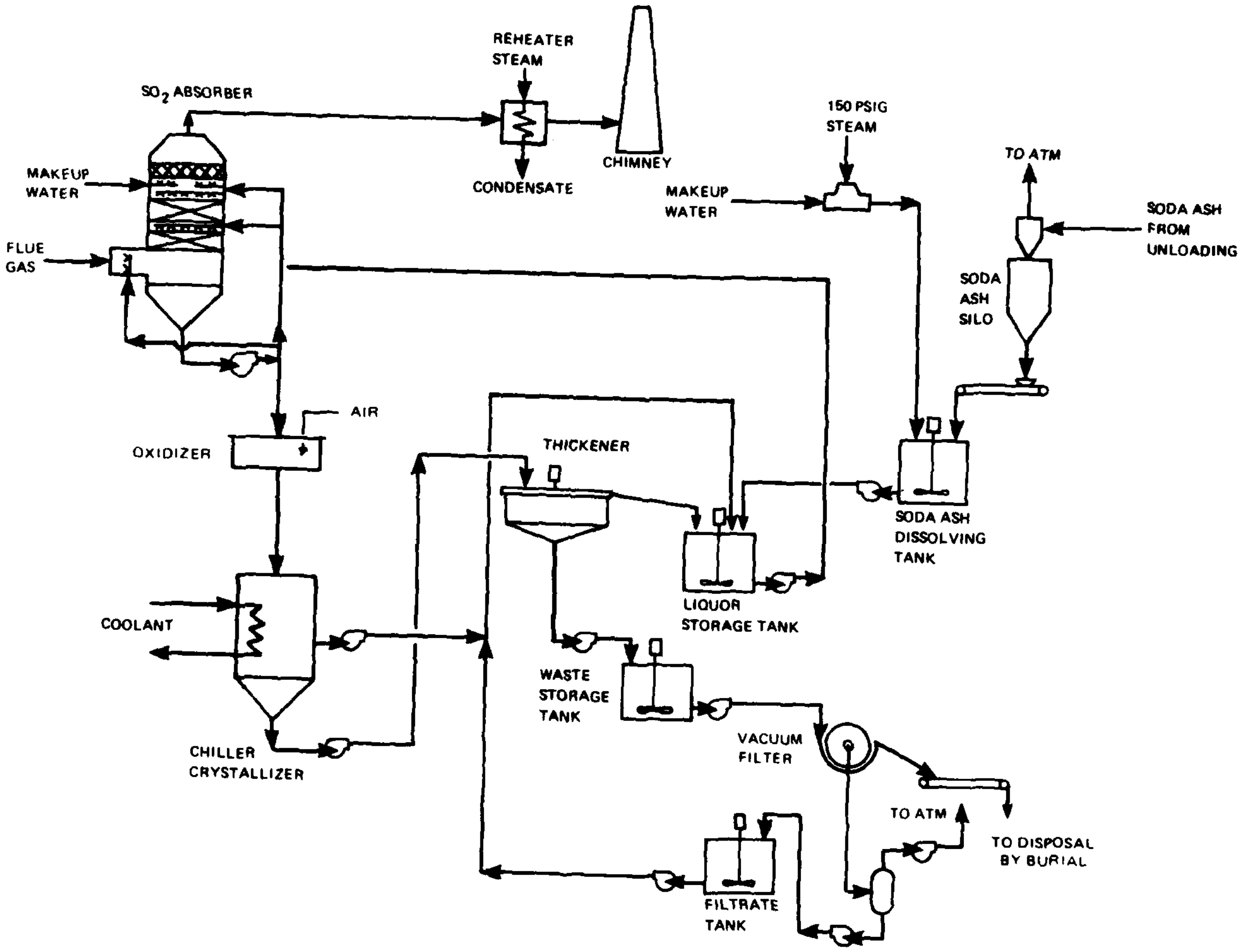


Figure 3-4
SODA LIQUOR WET SCRUBBING PROCESS WITH SOLID WASTE DISPOSAL

The absorber effluent liquor is filtered to remove solids and divided into two streams, a portion going to the regeneration area and the remainder going to purge treatment to reject the unreactive sodium sulfate. Double-effect evaporator/crystallizers are used to convert the dissolved $NaHSO_3$ to crystalline Na_2SO_3 and liberated SO_2 by the reverse of reaction (1). The regenerated Na_2SO_3 crystals are dissolved and returned to the absorbers. The regenerated SO_2 stream is converted to elemental sulfur by reduction with natural gas in an Allied Chemical SO_2 reduction plant. Figure 3-5 is a flow diagram of the Wellman-Lord/Allied Chemical FGD process. Figure 3-6 is a simplified block flow diagram of the Allied Chemical SO_2 reduction process. As can be seen from the diagrams, this process is considerably more complex than the previous four processes.

Raw material handling facilities provide for receiving, storing, and dissolving soda ash. Makeup soda ash is conveyed pneumatically from self-unloading trucks to a slurry storage tank where it forms a crystal bed. The saturated sodium carbonate solution produced in the tank is drawn off through a floating suction line and pumped to the regenerated sodium sulfite dissolving tank to replace sodium lost in the purge salts cake. Condensate from the SO_2 regeneration section is sparged into the bottom of the slurry storage tank to maintain the liquor level above the crystal bed. A scrubbed vent is employed on the slurry storage tank to prevent loss of soda ash fines during truck unloading.

In the prescrubber section, hot flue gas from the ID fans passes through a venturi scrubber where it is cooled and chlorides and residual fly ash are removed. Makeup water is added to the prescrubber through wash sprays on their chevron mist eliminators. The slurry produced by back flushing the spent absorbent filters is also added to the prescrubber slurry loop to minimize makeup water requirements. A slip stream of the prescrubber slurry is pumped to a small ash pond to purge fly ash and chlorides from the loop.

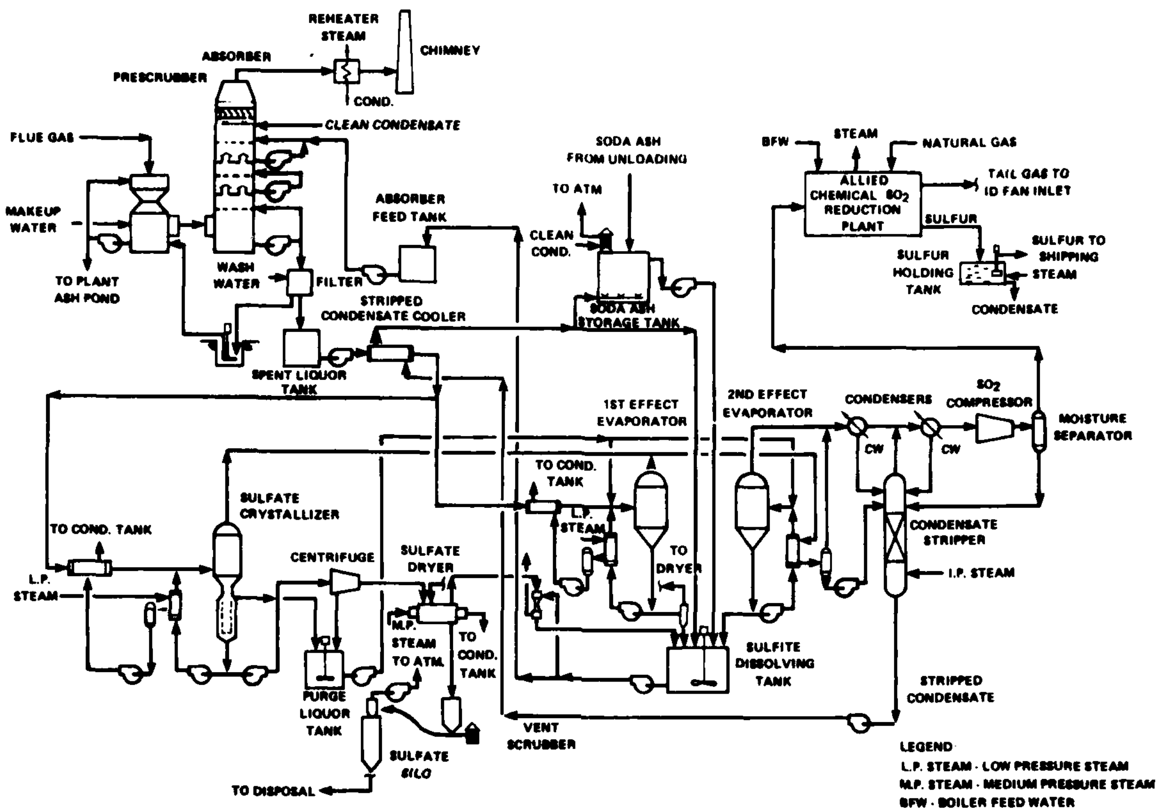


Figure 3-5
WELLMAN–LORD/ALLIED CHEMICAL PROCESS FLOW DIAGRAM

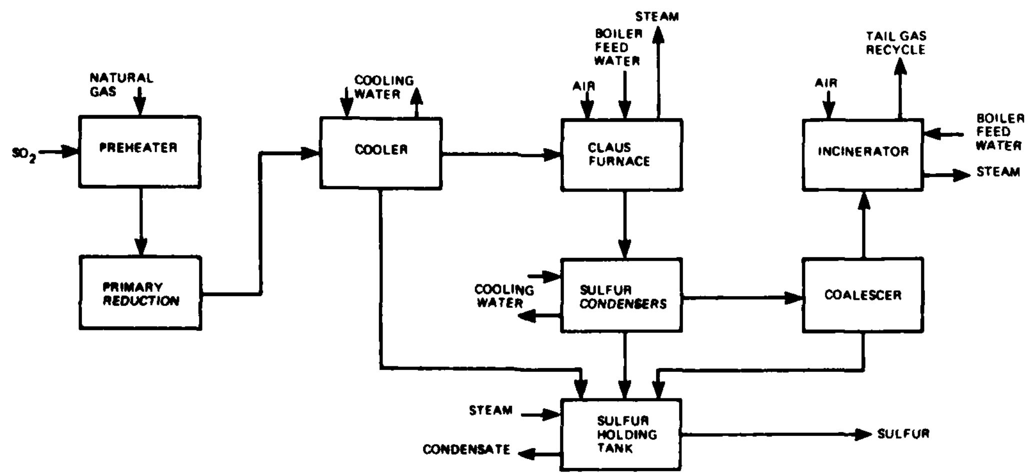


Figure 3-6
ALLIED CHEMICAL SO_2 REDUCTION PROCESS SIMPLIFIED BLOCK FLOW DIAGRAM

In the absorber section, saturated gas from the venturi prescrubbers passes through the absorber vessel where it is contacted with a sodium sulfite solution in a series of valve trays. Each of the upper trays has a collector tray which permits recirculation of absorbent to each contacting tray stage. Liquor overflowing from the bottom contacting tray is collected in the absorber bottom. Regenerated absorbent is added to the absorption loop as a makeup stream to the top contacting tray's recirculation loop. The cleaned flue gas passes through a chevron mist eliminator which removes entrained liquor droplets, and is then reheated before discharging to the chimney. Spent absorbent solution is collected from the absorber sump and pumped through a pressure-leaf filter for removal of particulate before flowing to the spent-liquor tank. The slurry produced by periodically sluicing the filter is collected and pumped to the prescrubber loop to minimize fresh makeup water requirements.

In the purge treatment section, a portion of the spent absorbent liquor is preheated and fed to a sulfate crystallizer. A liquid-solid separation chamber in the crystallizer produces a clear liquor overflow stream and a purge salt slurry stream. The slurry is centrifuged to separate the crystals from the remaining liquor. The centrate is combined with the crystallizer overflow liquor and pumped to the regeneration area. The overhead vapors from the sulfate crystallizer are also sent to the regeneration area. The wet cake from the centrifuge and a portion of the mother liquor from the first-effect evaporator are fed to a steam-heated dryer. The dried crystals are discharged into a sulfate surge hopper from which they are conveyed pneumatically to a storage bin. The dryer offgas passes through a vent gas scrubber for removal of SO_2, and is discharged to the atmosphere.

In the SO_2 regeneration section, the balance of the spent-absorbent liquor is combined with the purge liquor stream and fed to the double-effect evaporator. A purge stream of the mother liquor is separated from the

first-effect evaporator slurry stream and pumped to the sulfate dryer to control the level of unreactive sodium thiosulfate ($Na_2S_2O_3$) in the regenerated absorbent. The remaining slurry flows to the dissolving tank.

Overhead vapors from the first-effect evaporator and the sulfate crystallizer are partially condensed in the second-effect heater. The sour condensate produced is steam stripped in the condensate stripper to remove dissolved SO_2. Overhead vapor from the second-effect evaporator is combined with the uncondensed vapor from the second-effect heater and sent to the primary condenser, where most of the water is removed. The sour condensate from the primary condenser is also stripped to remove dissolved SO_2.

The vapor from the primary condenser is combined with the stripper overhead vapor and sent to the secondary condenser. The sour condensate from this condenser also flows to the stripper for removal of dissolved SO_2. Stripped condensate is cooled by exchanging heat with spent-absorbent liquor before it is returned to the dissolving tank.

The concentrated SO_2 stream from the secondary condenser is compressed and passes through a moisture separator before it is sent to the Allied Chemical SO_2 reduction plant. The moisture removed from the compressed SO_2 stream is sent to the condensate stripper for removal of dissolved SO_2.

Condensate is added to the slurry in the dissolving tank to redissolve the sulfite crystals. Soda ash solution from the soda ash storage tank is added to replace the sodium lost in the purge stream. A portion of the regenerated absorbent solution is pumped to the vent gas scrubber to remove SO_2 from the dryer vent gas. The regenerated absorbent solution is pumped from the dissolving tank to the absorber feed tank for storage.

In the Allied Chemical SO_2 reduction unit, the dried, compressed SO_2 gas is mixed with natural gas, preheated, and partially reduced in a catalytic

reactor to a mixture of sulfur, H_2S, and SO_2. The gases from the reduction stage are partially cooled to separate the sulfur, and the residual SO_2 and H_2S are converted to sulfur in a modified Claus catalytic reaction system. The molten product sulfur is stored in a concrete-lined, steam-heated pit for shipment in heated tank trucks. The tail gas from the reduction unit is incinerated with natural gas and air to oxidize residual H_2S to SO_2, after which it is returned to the inlet of the scrubbing system.

The Wellman-Lord/Allied Chemical process is considered uneconomical by the vendor for steam plant sizes below 400 x 10^6 Btu/hr, and in the cost comparisons of Section 4, this process is considered only at the 400 x 10^6 Btu/hr plant size.

This process is not recommended for Navy bases because of its complexity and the resulting impact on costs, operability, and reliability. This will be seen from information in Sections 4 to 8 and Section 13.

3.3 ANNUAL FLOWS

Annual flows of raw materials, utilities, by-products, and wastes of the five current FGD technologies described above are summarized in Table 3-1 for a steam plant sized to transfer 400 x 10^6 Btu/hr of heat into steam and operated at a 50 percent load factor.

Annual flows for smaller plants and for a 25 percent load factor can be obtained by taking ratios based on the values in Table 3-1.

Limestone is the principal reagent for the limestone slurry process. Lime is the principal reagent for the lime slurry and double alkali processes. Small amounts of lime are used to stabilize solid waste products in the lime, limestone, and double alkali processes. Soda ash is the absorbent makeup material for the soda liquor, double alkali and Wellman-Lord processes.

Table 3-1

ANNUAL FLOWS OF RAW MATERIALS, UTILITIES, BY-PRODUCTS, AND WASTES OF CURRENT FGD TECHNOLOGIES*

Technology	Limestone Slurry	Lime Slurry	Double Alkali	Soda Liquor Solid Waste	Soda Liquor Liquid Waste	Wellman-Lord/Allied Chemical
Lime, tons/yr	910	8,510	7,330			
Limestone, tons/yr	14,630					
Soda Ash, tons/yr			670	11,210	11,210	550
Water, 10^3 gal/yr	19,500	19,200	18,500	18,400	25,500	414,400
Steam, 10^3 lb/yr	42,500	42,500	42,500	42,500	42,500	123,800
Electricity, MWhr/yr	4,870	4,220	2,010	4,910	2,010	4,240
Scrubber Waste, tons/yr**	38,600	34,800	31,800	29,600	59,200	710
Natural Gas, 10^3 scf/yr						42,300
Elemental Sulfur, tons/yr						3,200

*Based on combustion of 50,700 tons per year of the coal of Section 2; combined excess combustion air and inleakage before entry to the scrubber is 60 percent of stoichiometric air; 3 percent of the coal carbon leaves unburned with the ash; char plus fly ash streams total 20,100 tons per year. These flows are expected for a steam plant with an output of 400 million Btu per hour operating at 50 percent load factor.

**Tonnages refer to sludge containing 50 percent solids for limestone slurry, lime slurry, and double alkali processes, refer to drained crystals containing approximately 50 percent water of hydration for the soda liquor solid waste and Wellman-Lord processes, and refer to a solution containing 25 percent dissolved salts for the soda liquor process with liquid waste.

Water supplied to the first four processes in Table 3-1 replaces water lost with the solid waste and water lost in flue gas saturation. These four processes consume approximately the same amount of water. However, the fifth process, the Wellman-Lord/Allied Chemical process, requires additional water for cooling and processing during the recovery and reduction of SO_2.

The steam consumed by the first four processes in Table 3-1 is used mainly for flue gas reheating. The Wellman-Lord/Allied Chemical process consumes additional steam for evaporator heating.

Electricity is used in all five processes listed in Table 3-1 for driving flue gas through the absorber and reheater and for circulating scrubbing slurry or liquor. Since the volumetric flow rate of clear liquor scrubbing agent is lower than that of the lime and limestone slurries, the power consumption for scrubbing agent circulation is lower for the double alkali, soda, and Wellman-Lord/Allied Chemical processes. Waste crystallization operations in the soda liquor with solid waste disposal and the Wellman-Lord/Allied Chemical processes consume additional electric power, making their total power comsumption comparable to the lime slurry and limestone slurry processes.

Since the Wellman-Lord/Allied Chemical process converts most of the absorbed SO_2 into a salable by-product, it produces the least solid waste among the five processes in Table 3-1. The waste in each case contains water and some unconsumed scrubbing agent in addition to the solid crystals.

Table 3-1 also shows the amounts of natural gas consumed and elemental sulfur produced by the Wellman-Lord/Allied Chemical process.

Fly ash removed upstream of the FGD systems must also be disposed of as solid waste. The cost of waste disposal chargeable to the FGD systems is calculated as the difference between the cost of disposing of ash plus FGD

waste and the cost of disposing of ash only. This method of calculation is necessary since the cost of disposal is not linear with annual flow for small facilities, as discussed in Section 4.

3.4 OPERATING MANPOWER REQUIREMENTS

The annual operating labor manhours required are shown in Table 3-2. These provide at least one operator per shift dedicated to the scrubber in all cases, with additional assistance borrowed from the boiler operating staff increasing with system size. The Wellman-Lord/Allied Chemical system would require an additional man per shift.

Table 3-2

ANNUAL OPERATING LABOR MANHOURS

Installation size, 10^6 Btu/hr	25	50	100	200	400
Lime, Limestone, Double Alkali, Soda Liquor with Solids Disposal	9,700	11,000	12,300	16,000	19,000
Wellman-Lord/Allied Chemical	--	--	--	--	27,000
Soda Liquor with Liquids Disposal	9,000	10,000	11,000	13,000	14,250

3.5 WASTE DISPOSAL

An investigation of waste disposal options should be a significant part of site specific studies for any proposed FGD installation.

In this study it is assumed that a Navy base will not have land suitable for a disposal site, and that for an annual fee, a contractor will haul FGD wastes to a site he owns and operates. The disposal cost is assumed to depend upon the FGD process and the characteristics of its waste. The site is assumed to be in the eastern United States where there is net positive rainfall. Measures will be needed to prevent unwanted leaching of soluble waste salts into streams and aquifers.

The sludge from the limestone or the lime FGD process contains low solubility calcium sulfite and sulfate salts. It is assumed that this sludge can be deposited as land fill with a top dressing to minimize percolation and leaching of more soluble constituents.

The sludge from the double alkali process contains small amounts of sodium sulfite and sulfate along with the calcium salts. It is assumed that the bottom of the disposal site must be lined with clay to prevent contact between sodium salt and underground aquifers.

Waste solid crystals from the sodium carbonate process and the small purge of solid crystals from the Wellman-Lord process are very water soluble. It is assumed that these must be encapsulated with clay linings on bottom, sides, and top to prevent contact with aquifers.

In prescribing landfill disposal for lime and limestone systems, it has been assumed that the soil at the disposal site contains a moderate amount of clay and is somewhat impervious. Soil permeability will be a factor in determining the correct disposal design for any proposed disposal site.

Limestone, lime, and double alkali sludges are assumed to be stabilized. This means that the sludge has a solid rather than a fluid consistency. Stabilization of the sludges is accomplished by blending fly ash with the scrubber waste cake, and adding a small amount of lime. This procedure is useful for the processes which produce waste crystals predominantly in the form of calcium sulfite, which does not dewater easily. Section 9 discusses the advantage of converting sulfite waste to the easily dewatered sulfate (gypsum) form by forced oxidation.

It is assumed that liquid wastes from sodium carbonate scrubbing will be hauled to an aqueous disposal facility for disposal. The waste will consist of dissolved sodium sulfate, a naturally occurring constituent in the water of oceans and most rivers. The liquid wastes will weigh approximately twice as much as the equivalent amount of solid hydrated crystals from soda liquor scrubbing, because the liquid contains diluent water. For this reason, the disposal cost for the liquid waste process in Section 4 is estimated to be twice as high as that for the solid waste option.

Section 4

COSTS OF CURRENT TECHNOLOGIES

4.1 INTRODUCTION

In this section, capital, annual, and life-cycle costs are given for current FGD technologies.

4.2 CAPITAL AND ANNUAL COSTS

4.2.1 FGD Systems Capital Costs

The capital cost estimates presented in the economic portions of this study are based on quotes from FGD system vendors and Bechtel experience in constructing FGD systems and chemical process plants.

Capital costs for double alkali FGD systems spanning the range of sizes considered here were obtained from vendors during prior phases of this contract. Appendix D contains two updated tables from the Final Report for Phases II and III (Reference 2) detailing capital costs of double alkali systems and those of accompanying particulate removal systems. The double alkali capital costs used in this study are taken from the tables in Appendix D.

Capital costs for lime and limestone systems obtained from vendors are found to overlap double alkali costs over the range of sizes considered here, and differences between the three systems were judged to be not significant. Consequently, these two processes were assigned the same capital costs as the double alkali system.

The soda liquor process producing solid wastes resembles the double alkali system in process complexity and was likewise assigned the same capital cost as the double alkali system.

Although the above four processes appear to have essentially equivalent capital costs when compared generically here, a site specific study for any actual proposed installation may show the capital costs of any one of the four processes to be significantly lower than the others.

The soda liquor process producing liquid wastes is the simplest system considered. Informal vendor quotes reveal capital costs approximately half those for the corresponding double alkali system.

The Wellman-Lord/Allied Chemical vendor quoted capital costs more than twice those for a double alkali system. The Wellman-Lord/Allied Chemical system configuration for the 400 x 10^6 Btu/hr output boiler plant contains two absorber trains and one common regeneration and sulfur recovery train.

4.2.2 Facilities Included

As indicated in Section 2, the flue gas desulfurization system includes gas ducting, booster fans, gas presaturation, SO_2 absorption, absorbent preparation and circulation, waste solid preparation and temporary storage, sulfur by-product recovery systems, where applicable, and exit gas reheat heat exchangers.

4.2.3 Direct Field Costs

Direct field costs include equipment and materials plus direct construction labor. The major equipment costs assume that engineering and development costs have been spread over many installations.

The labor rate of $13 per man-hour given in Section 2 reflects a craft mix appropriate to the type of construction together with a 5 percent allowance for casual overtime and 1 percent for craft-furnished supervision. Sufficient manual labor to complete the project is assumed to be available in the project vicinity.

4.2.4 Indirect Field Costs

Indirect field costs are those items of construction cost that cannot be ascribed to direct portions of the facility and thus are accounted separately. They were estimated by modifying experience on similar plants, resulting in an assessment of 80 percent of direct labor costs, which has been distributed over the installation of direct equipment and materials as a function of the installation costs.

The items covered by indirect field costs are:

- Temporary Construction Facilities: temporary buildings, working areas, roads, parking areas, utility systems, and general-purpose scaffolding
- Miscellaneous Construction Services: general job cleanup, maintenance of construction equipment and tools, materials handling, and surveying
- Construction Equipment and Supplies: construction equipment, small tools, consumable supplies, and purchased utilities
- Field Office: field labor of craft supervisors, engineering, procurement, scheduling, personnel administration, warehousing, first aid, and the costs of operating the field office
- Preliminary Checkout and Acceptance Testing: testing of materials and equipment to ensure that components and systems are operable

4.2.5 Engineering Services

Engineering services include engineering costs, other home office costs, and fees. Engineering includes preliminary engineering, optimization

studies, specifications, detail engineering, vendor-drawing review, site investigation, and support to vendors. Other home-office costs comprise procurement, estimating and scheduling services, quality assurance, acceptance testing, and construction and project management. Fees are included as a function of the total project cost.

The sum of these three categories falls into historically consistent percentages in the range of 10 to 20 percent depending on the complexity of the project. For this study a figure of 12 percent of field construction costs has been used.

4.2.6 Contingency

Included in each estimate and each tabulated line item is a 20 percent contingency or allowance for the uncertainty that exists within the conceptual design in quantity, pricing, or productivity and that is under the control of the constructor and within the scope of the project as defined. Implicitly, the allowance will be expended during the design and construction of the project and it cannot be considered as a source of funds for overruns or additions to the project scope. Thus, if the conceptual arrangement of the plant components contains major uncertainties, or the design duty of plant components proves to be more severe than anticipated, or if additional major subsystems are ultimately found to be necessary, then the scope of the project is deemed to have been inadequately defined and this then would not be covered by the allowance.

4.2.7 Exclusions

The following items are excluded from the project scope and are not therefore included in the estimates:

- Any special construction such as widening and strengthening existing roads
- Client Engineering
- Site investigation and land acquisition

4.2.8 The Term "Total Construction Cost"

Capital costs in this report contain the following functional costs described above:

- Direct field costs
- Indirect field costs
- Engineering services
- Contingency

Costs containing these elements are known as "total construction costs," or costs "at the total construction cost level."

4.2.9 Startup

Startup costs were estimated as a percentage of total construction cost. The figure used for this study was 11 percent and reflects experience for similar plants. It includes process royalties, spare parts inventory, initial charge of catalysts and chemicals, actual plant startup operations, training of operators, and the owner's home office costs for management, reports, permits, etc.

4.2.10 Operating Labor

The $20 per man-hour labor rate includes overhead, administration, and supervision, as follows:

• Base wage per hour		$ 8.00
• Payroll tax and insurance	+ 8%	+ 0.65
• Allowance for paid absences	+13%	+ 1.05
• Social and retirement benefits	+11%	+ 0.90
• Total direct labor		10.60
• Supervision as a percentage of direct labor	+25%	+ 2.70
• Total direct plus supervision		13.30
• Administration and overhead as a percentage of direct labor and supervision	+50%	+ 6.70
• Total labor rate		$20.00

The total operating labor costs are the product of this rate and the man-hours worked by the labor forces taken from Table 3-2. The labor force is assumed the same for both 25 and 50 percent load factor.

4.2.11 Operating Supplies

Operating supplies are priced at 8 percent of operating labor cost.

4.2.12 Maintenance Labor

Maintenance labor has been taken as 2 percent of the total construction cost.

4.2.13 Maintenance Materials

Maintenance materials have been taken as 4 percent of the total construction cost.

4.2.14 Utilities and Chemicals

Electricity, gas, steam, and chemicals are costed according to the rates given in Section 2 and the quantities given in Section 3, using ratios for size and load factor.

4.2.15 Waste Disposal Contract

The following costs per ton for disposal of wastes are cited in the order of increasing disposal difficulties:

- Limestone and lime wet sludge: $5/ton
- Double alkali wet sludge: $6/ton
- Drained hydrated crystal wastes from soda liquor and Wellman-Lord processes: $10/ton
- Liquid soda liquor wastes, tonnage based on solution containing 25 percent dissolved salts: $10/ton

4.2.16 Technology Comparisons

Tables 4-1 through 4-5 display capital and annual costs for the five current technologies in five installation sizes and at a load factor of 50 percent. As mentioned in Section 3, the Wellman-Lord/Allied Chemical process has not been considered at sizes below 400 x 10^6 Btu/hr. Table 4-6 presents a summary of the information in Tables 4-1 to 4-5.

Costs for a load factor of 25 percent are presented in Tables E-1 to E-5 in Appendix E and summarized in Table 4-7.

4.3 LIFE-CYCLE COSTS

4.3.1 Present Values

Life-cycle present values were calculated by the Navy methodology described in Section 2 and Appendices A, B, and C. Such calculations were made for each combination of technology, installation size, and load factors. Table 4-8 presents the calculation details for a typical

case, a 400 x 10^6 Btu/hr double alkali plant at a 50 percent load factor. The results for all technologies, sizes, and load factors are displayed in Appendix E.

Unit present values in dollars per million Btu of coal heat provide the best measure for comparing the life-cycle costs of energy related alternatives. The unit present values from the tables in Appendix E are presented in Tables 4-9 and 4-10.

4.3.2 Levelized Costs

Unit present values from Table 4-9 and 4-10 were converted to 1979 levelized costs by the method described in Section 2. The results are shown in Tables 4-11 and 4-12.

4.4 RANKINGS FOR TECHNOLOGIES

Inspection of the levelized costs in Tables 4-11 and 4-12 shows the following:

- At the sizes and load factors considered, the lowest cost system is sodium carbonate scrubbing with liquid disposal. However, future environmental regulations may make it more difficult to use this process in many localities

- The calcium-based throwaway limestone slurry, lime slurry, and double alkali processes have comparable costs in all sizes and load factors

- Sodium carbonate scrubbing with solid crystal disposal costs slightly more than the three calcium-based throwaway processes, because of higher reagent and disposal costs

- The Wellman-Lord/Allied Chemical recovery process costs significantly more than the other five processes in the one size in which it was considered

Table 4-1

CAPITAL AND ANNUAL OPERATING COSTS FOR
400 MILLION BTU PER HOUR FACILITIES
(50% Load Factor)

Cost Item	Lime-stone	Lime	Double Alkali	Soda Liquor Solid Waste	Soda Liquor Liquid Waste	Wellman-Lord/ Allied Chemical
Approximate Capital Cost						
Total Construction Cost	6,660	6,660	6,660	6,660	3,330	15,000
Startup	730	730	730	730	360	1,650
Total Capital	7,330	7,330	7,330	7,330	3,660	16,650
Annual Operating Cost						
Electricity	161	139	67	162	70	140
Natural Gas	—	—	—	—	—	102
Steam	226	226	226	226	226	659
Water	7	7	7	7	10	145
Chemicals	192	425	414	785	785	38
Operating Labor	380	380	380	380	290	540
Operating Supplies	30	30	30	30	23	43
Maintenance Labor	132	132	132	132	66	300
Maintenance Material	264	264	264	264	132	600
Waste Disposal Contact	96	87	95	148	296	4
Total Annual Operating Cost	1,488	1,690	1,609	2,134	1,898	2,571
Annual Operating $\$/10^6$ Btu	0.88	0.96	0.92	1.22	1.08	1.47

Costs in thousands of second quarter 1978 dollars.
Annual operating dollars per million Btu do not contain capital charges.
Annual boiler output is 1,752 billion Btu.
Annual operating costs were computed using flows in Table 3-1 on page 3-17.

Table 4-2

CAPITAL AND ANNUAL OPERATING COSTS FOR
200 MILLION BTU PER HOUR FACILITIES
(50% Load Factor)

Cost Item	Lime-stone	Lime	Double Alkali	Soda Liquor Solid Waste	Soda Liquor Liquid Waste
Approximate Capital Cost					
Total Construction Cost	4,200	4,200	4,200	4,200	2,100
Startup	460	460	460	460	230
Total Capital	4,660	4,660	4,660	4,660	2,330
Annual Operating Cost					
Electricity	81	70	34	81	35
Natural Gas	—	—	—	—	—
Steam	113	113	113	113	113
Water	4	4	4	4	6
Chemicals	96	213	207	393	393
Operating Labor	320	320	320	320	260
Operating Supplies	26	26	26	26	21
Maintenance Labor	84	84	84	84	42
Maintenance Material	168	168	168	168	84
Waste Disposal Contract	48	44	48	74	148
Total Annual Operating Cost	940	1,041	1,004	1,211	1,148
Annual Operating $/10^6$ Btu	1.07	1.19	1.15	1.38	1.31

Costs in thousands of second quarter 1978 dollars.
Annual operating dollars per million Btu do not contain capital charges.
Annual boiler output is 876 billion Btu.
Annual flows used for annual operating costs are 1/2 of those in Table 3-1 on page 3-17.

Table 4-3

CAPITAL AND ANNUAL OPERATING COSTS FOR
100 MILLION BTU PER HOUR FACILITIES
(50% Load Factor)

Cost Item	Lime-stone	Lime	Double Alkali	Soda Liquid Solid Waste	Soda Liquor Liquid Waste
Approximate Capital Cost					
Total Construction Cost	2,360	2,360	2,360	2,360	1,180
Startup	260	260	260	260	130
Total Capital	2,620	2,620	2,620	2,620	1,310
Annual Operating Cost					
Electricity	41	35	17	41	17
Natural Gas	—	—	—	—	—
Steam	57	57	57	57	57
Water	2	2	2	2	3
Chemicals	48	107	104	197	197
Operating Labor	246	246	246	246	220
Operating Supplies	20	20	20	20	18
Maintenance Labor	52	52	52	52	26
Maintenance Material	105	105	105	105	52
Waste Disposal Contract	24	22	24	37	74
Total Annual Operating Cost	595	646	627	757	664
Annual Operating $\$/10^6$ Btu	1.36	1.47	1.43	1.73	1.51

Costs in thousands of second quarter 1978 dollars.
Annual operating dollars per million Btu do not contain capital charges.
Annual boiler output is 438 billion Btu.
Annual flows used for annual operating costs are 1/4 of those in Table 3-1 on page 3-17.

Table 4-4

CAPITAL AND ANNUAL OPERATING COSTS FOR
50 MILLION BTU PER HOUR FACILITIES
(50% Load Factor)

Cost Item	Lime-stone	Lime	Double Alkali	Soda Liquid Solid Waste	Soda Liquor Liquid Waste
Approximate Capital Cost					
Total Construction Cost	1,360	1,360	1,360	1,360	680
Startup	150	150	150	150	75
Total Capital	1,510	1,510	1,510	1,510	755
Annual Operating Cost					
Electricity	21	18	9	21	9
Natural Gas	—	—	—	—	—
Steam	29	29	29	29	29
Water	1	1	1	1	1
Chemicals	24	54	52	99	99
Operating Labor	220	220	220	220	200
Operating Supplies	18	18	18	18	16
Maintenance Labor	27	27	27	27	14
Maintenance Material	54	54	54	54	27
Waste Disposal Contract	12	11	12	18	37
Total Annual Operating Cost	406	432	423	487	432
Annual Operating $/10^6$ Btu	1.85	1.97	1.93	2.22	1.97

Costs in thousands of second quarter 1978 dollars.
Annual operating dollars per million Btu do not contain capital charges.
Annual boiler output is 219 billion Btu.
Annual flows used for annual operating costs are 1/8 those in Table 3-1 on page 3-17.

Table 4-5

CAPITAL AND ANNUAL OPERATING COSTS FOR
25 MILLION BTU PER HOUR FACILITIES
(50% Load Factor)

Cost Item	Lime-stone	Lime	Double Alkali	Soda Liquor Solid Waste	Soda Liquor Liquid Waste
Approximate Capital Cost					
Total Construction Cost	930	930	930	930	465
Startup	100	100	100	100	50
Total Capital	1,030	1,030	1,030	1,030	515
Annual Operating Cost					
Electricity	11	9	5	11	5
Natural Gas	—	—	—	—	—
Steam	14	14	14	14	14
Water	—	—	—	—	—
Chemicals	12	27	26	50	50
Operating Labor	194	194	194	194	180
Operating Supplies	16	16	16	16	14
Maintenance Labor	19	19	19	19	9
Maintenance Material	37	37	37	37	19
Waste Disposal Contract	6	5	6	9	18
Total Annual Operating Cost	309	321	317	350	309
Annual Operating $\$/10^6$ Btu	2.82	2.93	2.89	3.20	2.82

Costs in thousands of second quarter 1978 dollars.
Annual operating dollars per million Btu do not contain capital charges.
Annual boiler output is 110 billion Btu.
Annual flows used for annual operating costs are 1/16 of those in Table 3-1 on page 3-17.

Table 4-6

SUMMARY OF CAPITAL AND ANNUAL OPERATING COSTS
FOR 50 PERCENT LOAD FACTOR

Installation Size	Cost Item	Limestone	Lime	Double Alkali	Soda Liquor Solid Waste	Soda Liquor Liquid Waste	Wellman-Lord/Allied Chemical
400×10^6 Btu/hr	Capital Cost	7,330	7,330	7,330	7,330	3,660	16,650
	Annual Operating Cost	1,488	1,690	1,609	2,134	1,898	2,571
	Unit Annual Operating Cost, $\$/10^6$ Btu	0.85	0.96	0.92	1.22	1.08	1.47
200×10^6 Btu/hr	Capital Cost	4,660	4,660	4,660	4,660	2,330	
	Annual Operating Cost	940	1,042	1,004	1,211	1,148	
	Unit Annual Operating Cost, $\$/10^6$ Btu	1.07	1.19	1.15	1.38	1.31	
100×10^6 Btu/hr	Capital Cost	2,620	2,620	2,620	2,620	1,310	
	Annual Operating Cost	595	646	627	757	664	
	Unit Annual Operating Cost, $\$/10^6$ Btu	1.36	1.47	1.43	1.73	1.51	
50×10^6 Btu/hr	Capital Cost	1,510	1,510	1,510	1,510	755	
	Annual Operating Cost	406	432	423	487	432	
	Unit Annual Operating Cost, $\$/10^6$ Btu	1.85	1.97	1.93	2.22	1.97	
25×10^6	Capital Cost	1,030	1,030	1,030	1,030	515	
	Annual Operating Cost	309	321	317	350	309	
	Unit Annual Operating Cost, $\$/10^6$ Btu	2.82	2.93	2.89	3.20	2.82	

Capital and annual operating costs in thousands of second quarter 1978 dollars.
Annual operating and unit annual operating costs do not contain capital charges.

Table 4-7

SUMMARY OF CAPITAL AND ANNUAL OPERATING COSTS
FOR 25 PERCENT LOAD FACTOR

Installation Size	Cost Summary	Limestone	Lime	Double Alkali	Soda Liquor Solid Waste	Soda Liquor Liquid Waste	Wellman-Lord/Allied Chemical
400×10^6 Btu/hr	Capital Cost	7,330	7,330	7,330	7,330	3,660	16,650
	Annual Operating Cost	1,148	1,250	1,212	1,471	1,203	2,028
	Unit Annual Operating Cost, $\$/10^6$ Btu	1.31	1.43	1.38	1.68	1.37	2.32
200×10^6 Btu/hr	Capital Cost	4,660	4,660	4,660	4,660	2,330	
	Annual Operating Cost	770	821	802	932	755	
	Unit Annual Operating Cost $\$/10^6$ Btu	1.76	1.87	1.83	2.13	1.72	
100×10^6 Btu/hr	Capital Cost	2,620	2,620	2,620	2,620	1,310	
	Annual Operating Cost	510	536	526	591	491	
	Unit Annual Operating Cost, $\$/10^6$ Btu	2.33	2.45	2.40	2.70	2.24	
50×10^6 Btu/hr	Capital Cost	1,510	5,150	1,510	1,510	755	
	Annual Operating Cost	362	374	370	403	344	
	Unit Annual Operating Cost, $\$/10^6$ Btu	3.31	3.42	3.38	3.68	3.14	
25×10^6 Btu/hr	Capital Cost	1,030	1,030	1,030	1,030	515	
	Annual Operating Cost	288	295	292	309	266	
	Unit Annual Operating Cost, $\$/10^6$ Btu	5.26	5.39	5.33	5.64	4.86	

Capital and annual operating costs in thousands of second quarter 1978 dollars. Annual operating and unit annual operating costs do not contain capital charges.

Table 4-8

SAMPLE PRESENT VALUE AND LEVELIZED COST CALCULATION

TECHNOLOGY: Double Alkali
SIZE: 400 million Btu per Hour
LOAD FACTOR: 50 Percent

Cost Item	Differential Inflation Rate %	Project Year	Amount*		Discount Factor	Present Values*
			One Time	Recurring		
1st Year Construction	+ 0	2	2,443		0.867	2,118
2nd Year Construction	+ 0	3	4,887		0.788	3,851
Total Investment			7,330		—	5,969
Electricity	+ 6	4-28		67	14.588	977
Gas (for Sulfur Reduction)	+10	4-28		--	25.000	--
All Other Annual Cost	+ 0	4-28		1,542	7.156	11,035
Total Annual Cost				1,609		12,012
Total Project Present Value ($1000s)						17,981
Total Heat Loads Over 25 Years, 10^9 Btu						43,800
Unit Energy Present Value, $\$/10^6$ Btu						0.41
Levelized Unit Energy Cost (in 1979 Dollars) $\$/10^6$ Btu						1.55

*One time and recurring amounts and present values are in thousands of second quarter 1978 dollars.

Table 4-9

1978 UNIT PRESENT VALUES
FOR 50 PERCENT LOAD FACTOR
IN DOLLARS PER MILLION BTU

Installation Size	Lime-stone	Lime	Double Alkali	Soda Liquor Solid Waste	Soda Liquor Liquid Waste	Wellman-Lord/Allied Chemical
400 x 10^6 Btu/hr	0.41	0.44	0.41	0.51	0.39	0.79
200 x 10^6 Btu/hr	0.50	0.53	0.51	0.59	0.47	
100 x 10^6 Btu/hr	0.61	0.63	0.61	0.71	0.54	
50 x 10^6 Btu/hr	0.78	0.81	0.78	0.88	0.69	
25 x 10^6 Btu/hr	1.13	1.16	1.14	1.24	0.97	

Table 4-10

1978 UNIT PRESENT VALUES
FOR 25 PERCENT LOAD FACTOR
IN DOLLARS PER MILLION BTU

Installation Size	Lime-stone	Lime	Double Alkali	Soda Liquor Solid Waste	Soda Liquor Liquid Waste	Wellman-Lord/Allied Chemical
400×10^6 Btu/hr	0.68	0.70	0.68	0.78	0.54	1.35
200×10^6 Btu/hr	0.87	0.90	0.87	0.97	0.67	
100×10^6 Btu/hr	1.07	1.10	1.08	1.18	0.84	
50×10^6 Btu/hr	1.41	1.44	1.42	1.52	1.13	
25×10^6 Btu/hr	2.13	2.16	2.14	2.24	1.70	

Table 4-11

1979 LEVELIZED COSTS
FOR 50 PERCENT LOAD FACTOR
IN DOLLARS PER MILLION BTU

Installation Size	Lime-stone	Lime	Double Alkali	Soda Liquor Solid Waste	Soda Liquor Liquid Waste	Wellman-Lord/Allied Chemical
400 x 10^6 Btu/hr	1.54	1.65	1.55	1.94	1.47	3.00
200 x 10^6 Btu/hr	1.90	2.01	1.92	2.23	1.78	
100 x 10^6 Btu/hr	2.29	2.40	2.31	2.69	2.04	
50 x 10^6 Btu/hr	2.93	3.05	2.96	3.34	2.59	
25 x 10^6 Btu/hr	4.29	4.39	4.31	4.69	3.66	

Table 4-12

1979 LEVELIZED COSTS
FOR 25 PERCENT LOAD FACTOR
IN DOLLARS PER MILLION BTU

Installation Size	Lime-stone	Lime	Double Alkali	Soda Liquor Solid Waste	Soda Liquor Liquid Waste	Wellman-Lord/Allied Chemical
400×10^6 Btu/hr	2.55	2.66	2.57	2.95	2.04	5.09
200×10^6 Btu/hr	3.27	3.39	3.29	3.68	2.54	
100×10^6 Btu/hr	4.05	4.17	4.07	4.45	3.18	
50×10^6 Btu/hr	5.33	5.43	5.35	5.74	4.27	
25×10^6 Btu/hr	8.06	8.17	8.08	8.47	6.44	

Section 5

EFFICIENCY OF CURRENT TECHNOLOGIES

The efficiency of SO_2 removal among the various technologies depends in part upon the particular requirements and design of a given installation. However, it is possible to rank the technologies in a general way according to their inherent efficiency for SO_2 removal.

Clear liquor scrubbing systems offer greater removal potential than slurry systems, because the reagent is fully dissolved in the clear liquor whereas it must be continuously dissolved during SO_2 pickup in the slurry. Throwaway soda systems have a greater removal potential than calcium systems. The Wellman-Lord system must operate closer to the saturation level for maximum steam economy, and this may limit its removal capacity. Lime slurry has been shown to have greater removal efficiency than limestone slurry for a given percent of reagent utilization.

Table 5-1 is a judgment of the resulting ranking of the current technologies as to SO_2 removal efficiency.

Table 5-1

SO_2 REMOVAL EFFICIENCY RANKING OF CURRENT TECHNOLOGIES

Technology	Rank (Most Efficient Has Rank of 1)
Soda Liquor	1
Double Alkali	2
Wellman-Lord/Allied Chemical	3
Lime	3
Limestone	4

Note, however that all five technologies are capable of providing in excess of 90 percent SO_2 removal with proper design. Note also that additives discussed in Section 9 will probably increase the SO_2 removal efficiencies of the lime and limestone processes.

Section 6

OPERABILITY OF CURRENT TECHNOLOGIES

Operability* refers to the lack of difficulty encountered by operating personnel in making a system run smoothly and adequately.

Inadequate operability will be reflected in higher system operating costs. Some of the ways these costs appear include:

- Additional personnel needed for operating
- Higher wages for premium operator skills
- Training costs
- Costs of operation-caused equipment damage

Operability costs generally increase as a result of:

- New technology
- Complex processes (number of process steps)
- Interconnected process components and sensitivity to feedback
- Process sensitivity to changes in load factors
- High frequency of maintenance or manual adjustments
- Operator difficulty in understanding system or equipment function
- System operations requiring operator manual control within narrow tolerances
- Conditions requiring quick operator action to avert shutdown or aggravated equipment damage

---

* Note that the meaning of the term "operability" here differs from that used by EPA, quoted in Reference 11.

Operability costs are being progressively reduced in the chemical process and petroleum refining industries by proper instrumentation and automation. Characteristics of well automated plants include:

- Automatic adjustment for all normal operating functions
- Alarms which indicate anomalous conditions requiring operator decision or action
- Centralization of operator monitoring and adjustment functions

The rankings for operability below are based on a number of factors including experience with the development of FGD systems over the last decades and information obtained during site visits for this study. In general, the two process features that have greatest impact on operability are:

- Use of clear liquor scrubbing
- Process simplicity

Clear, sodium-based liquor is a simpler scrubbing agent than a limestone or lime slurry for the following two reasons:

- Clear liquor scrubbing involves lower risk of scale formation and solids buildup in the absorber (historically the most significant problem area in the development of FGD systems)
- The clear liquor is easier to pump than a slurry containing solids (pumps remain among the highest maintenance items in most current FGD systems)

The soda liquor, double alkali, and Wellman-Lord processes use clear liquor scrubbing. Consequently, from the standpoint of the scrubbing agent, these processes are simpler than lime and limestone processes.

Systems with fewer processing steps are simpler. The soda liquor process yielding liquid wastes contains the fewest components of all the systems

considered. The double alkali, limestone, and lime processes and the soda liquor process yielding solid wastes have comparable complexity. The Wellman-Lord/Allied Chemical process contains significantly more process steps than the other systems, and consequently is the least operable of the technologies.

The considerations above lead to the generic operability rankings shown in Table 6-1. However, a detailed site-specific study for a particular proposed installation may show any one of the first five technologies in the table to be more operable.

Table 6-1

RANKING OF OPERABILITY OF CURRENT TECHNOLOGIES

Technology	Rank (Most Operable Has Rank of 1)
Soda Liquor, Liquid Wastes	1
Double Alkali	2
Soda Liquor, Solid Wastes	2
Lime	3
Limestone	3
Wellman-Lord/Allied Chemical	4

Section 7

RELIABILITY OF CURRENT TECHNOLOGIES

The reliability of a system relates to its ability to perform its function on demand. Reliability is usually expressed as a probability that the system will function when called upon. The best measure of reliability is the availability, the fraction of time the system is not shut down for repair.

Although availability figures were collected or calculated for the installations studied in Task B and described in Sections 11 to 14, these figures constitute such a small sample that they cannot be considered wholly representative of their respective technologies.

In Table 7-1 below, rankings for reliability are given, which are based on several factors including experience with the development of FGD systems over the last decades and information obtained during site visits in this study. The rankings include process simplicity as a factor leading to greater reliability.

Table 7-1

RANKING OF RELIABILITY OF CURRENT TECHNOLOGIES

Technology	Rank (Most Reliable Has Rank of 1)
Soda Liquor, Liquid Wastes	1
Limestone	2
Lime	2
Double Alkali	2
Soda Liquor, Solid Wastes	2
Wellman-Lord/Allied Chemical	3

Section 8

MAINTAINABILITY OF CURRENT TECHNOLOGIES

Maintainability is defined in Reference 3 as the probability that a failure can be repaired by a work crew in a specified period of time. As stated in Section 2, a period of 8 hours has been specified in this study.

For the installations studied under Task B and described in Sections 11 to 15, maintainability figures were calculated from repair time information given by owners and system developers. The maintainabilities so calculated were essentially equivalent for four of the installations within the validity of the data. Only the Wellman-Lord/Allied Chemical installation repair times were significantly longer than the others, and this may be because it was a much larger installation than the others.

Nevertheless, the history of the development and operation of FGD systems indicates that maintainability is related to process simplicity. Accordingly, system simplicity has been used as the criterion for ranking the current technologies as to maintainability in Table 8-1.

Table 8-1

RANKING OF MAINTAINABILITY OF CURRENT TECHNOLOGIES

Technology	Rank (Most Maintainable Has Rank of 1)
Soda Liquor, Liquid Wastes	1
Limestone	2
Lime	2
Double Alkali	2
Soda Liquor, Solid Wastes	2
Wellman-Lord/Allied Chemical	3

Section 9

FUTURE TECHNOLOGIES

9.1 INTRODUCTION

This section contains descriptions of technologies which have not received extensive demonstration for industrial boiler application in the United States. They are called "future technologies" for the purposes of this study, even though all have received some successful pilot plant testing, many have been demonstrated and installed outside the United States, and each is offered for use by a commercial vendor.

The technologies described are meant to be representative. Those selected include a broad range of process types and also include some which have attracted substantial interest among potential users. However, no attempt was made to include all possible processes being proposed, developed, or marketed. Not included, for instance, is a double alkali process based on aluminum compounds developed by the Dowa Mining Company of Japan and currently being tested at the TVA Shawnee Test Facility. Instead, the Kawasaki magnesium-gypsum process was taken as representative of double alkali processes not based on soda scrubbing. Advantages, disadvantages, and rankings included below for the Kawasaki process may apply also to the Dowa process.

The processes are covered under the headings:

- Improved lime or limestone wet scrubbing systems
- The Chiyoda Thoroughbred 121 Jet Bubbling Reactor FGD system
- Other systems

At the end of this section, the future technologies are discussed as to suitability for use at Navy bases, and as to capital cost in comparison with current technologies.

9.2 IMPROVED LIME AND LIMESTONE WET SCRUBBING SYSTEMS

9.2.1 Forced Oxidation and Organic Acid Addition as Retrofits

Forced oxidation of over 90 percent of sludge calcium sulfite to calcium sulfate can be carried out by air sparging in a lime or limestone process. Calcium sulfate sludge has much better dewatering properties than calcium sulfite sludge; the water content of a calcium sulfate cake (gypsum) ranges from 10 to 20 percent as compared to 40 to 50 percent for a calcium sulfite cake. Dewatered gypsum sludge can be handled and stacked as a dry solid, and it does not have a chemical oxygen demand after removal from the plant site.

Organic acid additives appear to improve the performance of lime and limestone scrubbing systems. One promising additive is adipic acid (a six-carbon straight chain dicarboxylic acid) which is used as a raw material in nylon synthesis and also as a food additive. Adipic acid acts as a pH buffer and improves liquid phase mass transfer for SO_2 removal. Addition of adipic acid has increased SO_2 removal to as high as 95 percent and limestone utilization from 77 to 91 percent in limestone scrubbing systems. It works well with or without forced oxidation.

Both forced oxidation and adipic acid addition for lime and limestone systems are under study by EPA at the Tennessee Valley Authority (TVA) Shawnee test facility at Paducah, Kentucky. If the value of these enhancements is demonstrated in commercial scale tests, equipment for forced oxidation and acid addition could be added to most existing lime or limestone wet scrubbing processes as retrofits at minimum cost.

AD-A089 146 BECHTEL NATIONAL INC SAN FRANCISCO CA F/G 13/2
FLUE GAS DESULFURIZATION AT NAVY BASES, NAVY ENERGY GUIDANCE ST--ETC(U)
AUG 80 A I MCCONE N68305-77-C-0003
UNCLASSIFIED CEL-CR-80.023 NL

2 OF 3
AD A
089146

9.2.2 The Davy S-H Process

The Saarberg-Hoelter process offered in the United States by Davy Powergas, Inc., incorporates both forced oxidation and organic acid addition in a lime scrubbing system. The Davy S-H process adds formic acid for pH control. The vendor claims that the formic acid produces the complete dissolution of the calcium reagent, so that the scrubbing liquor is a clear solution, not a slurry. This process has been successfully demonstrated in Germany but not in the United States.

9.2.3 Magnesia As An Additive

Some tests have shown that the addition of magnesia to lime and limestone systems enhances SO_2 removal by providing more dissolved basic sulfite reagent to react with SO_2 (since magnesium sulfite is more soluble than calcium sulfite). Preliminary experiments managed by Bechtel at Shawnee show magnesia to be less effective, on a mole basis, than adipic acid for improving the efficiency of SO_2 removal and reagent utilization. Addition of appropriate amounts of magnesia can raise SO_2 removals up to about 95 percent, but at the expense of reliability.

9.3 THE CHIYODA THOROUGHBRED 121 PROCESS

Chiyoda Engineering and Construction Company of Japan is developing a second-generation process which features their "Jet Bubbling Reactor." The Chiyoda CT-121 process may be of interest for application at Navy bases because of its process simplicity. Absorption of SO_2, forced oxidation of calcium sulfite and bisulfite to calcium sulfate, and precipitation of calcium sulfate as gypsum are accomplished in a single reaction vessel. There are fewer moving parts in the process than in the classic limestone system.

Because of its unique design, Bechtel included the Chiyoda Thoroughbred 121 prototype plant among the facilities visited under Task B. The period of operation for the unit has been brief (approximately nine months). The prototype plant is located at Gulf Power Company's Scholz Station near

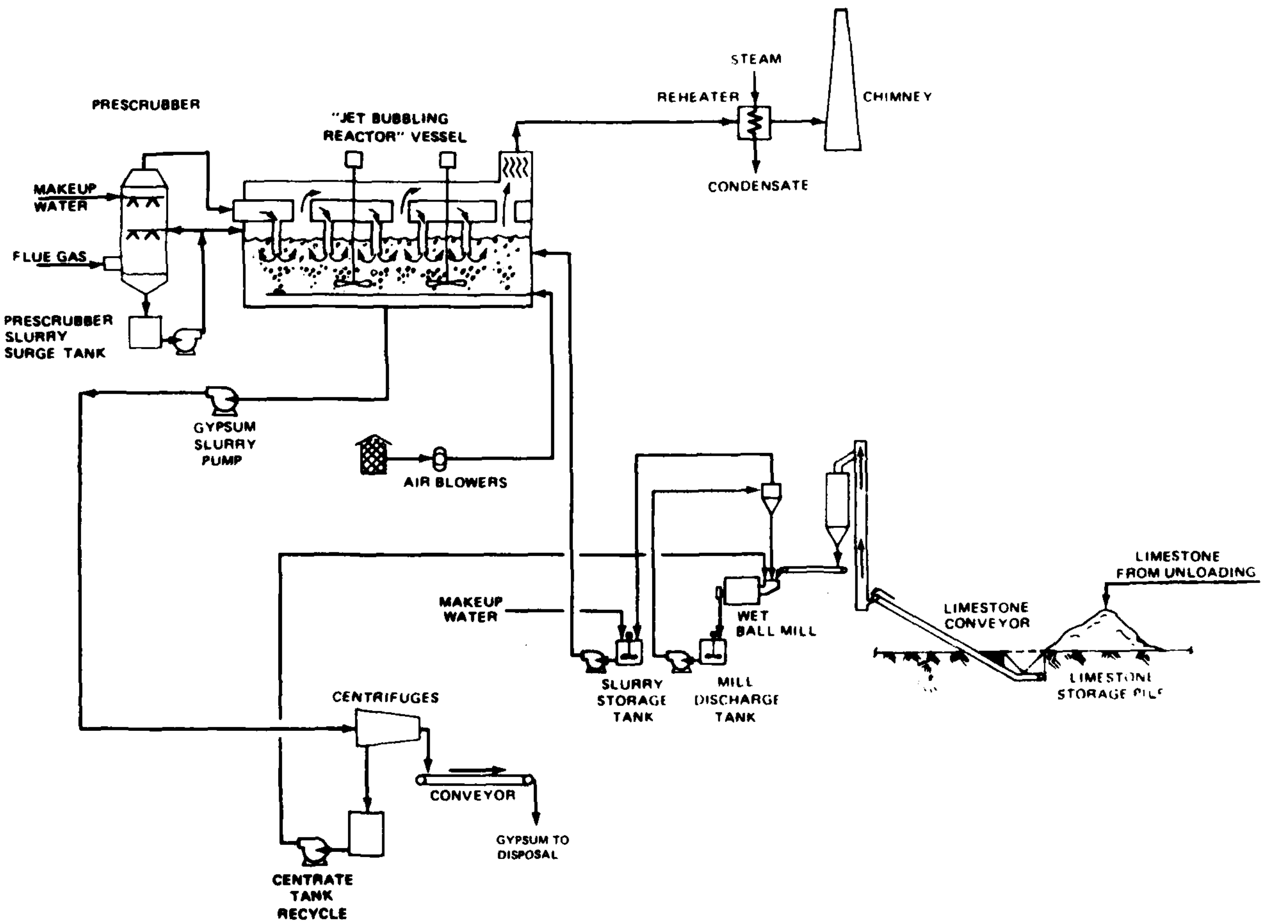


Figure 9-1
CHIYODA THOROUGHBRED 121
FGD PROCESS FLOW DIAGRAM

Tallahassee, Florida. Section 11 presents the results of the site study on the Chiyoda CT-121 plant at Scholz Station.

Figure 9-1 presents a flow diagram for the Chiyoda CT-121 process. Cooled, saturated flue gas is sparged into a tank containing a slurry of limestone and gypsum. The slurry is moderately stirred both by mechanical agitators and by oxidizing air which enters through distribution headers near the bottom of the vessel. The sparged gas creates a froth layer above the liquid in which SO_2 absorption and sulfite oxidation take place. The sulfates formed in the froth layer precipitate as gypsum crystals which grow as they circulate in the slurry bath until they reach sufficient size to settle to the bottom of the reaction vessel. Gypsum slurry is continually withdrawn from the bottom of the vessel. The slurry of waste gypsum can be dewatered by centrifuge as shown in the figure, or ponded as at Scholz Station.

In the future it may prove feasible to cool and saturate the flue gas in the gas inlet plenum at the top of the reactor rather than in a separate prescrubber vessel shown in the figure.

Chiyoda has claimed SO_2 removal levels exceeding 90 percent and reagent utilization approaching 100 percent in the tests of their CT-121 unit at Scholz Station. Radian Corporation has conducted an independent evaluation of these tests under the sponsorship of the Electric Power Research Institute (EPRI), and EPRI announced in January 1980 that the system performance is essentially as the vendor claims.

9.4 OTHER PROCESSES

9.4.1 Lime Spray Dryer/Fabric Filter Process

The lime slurry spray dryer/fabric filter process uses a slurry of hydrated lime ($Ca(OH)_2$), calcium sulfite, and fly ash to absorb SO_2 from flue gas by

contact with atomized droplets of the alkali slurry. The dry salt mixture produced is usually about 70 percent sulfite and 30 percent sulfate, with varying excesses of lime and calcium carbonate.

The atomized droplets rapidly evaporate in the spray dryer to produce a cooled and partially humidified particulate-laden gas from which most of the SO_2 has been removed. The mixture of fly ash, reaction products, and unreacted absorbent is removed from the gas stream in fabric filters. As the flue gas passes through the particulate-laden fabric, some additional SO_2 is absorbed by the remaining unreacted alkali, reducing the total amount of unreacted alkali in the filter cake.

Treated flue gas discharges from the fabric filters (baghouses) to the ID fans which discharge directly to the chimney. Individual groups of filter bags are periodically isolated from the flue gas stream and back-blown with clean flue gas to dislodge the filter cake, which is discharged from the baghouse hoppers and conveyed to storage.

Comparative costs for this process should include credits for reheat, and for carrying out particulate removal along with desulfurization in a common system.

Reagent utilization efficiency in this process is lower than in wet lime and limestone processes, and is an inverse function of sulfur content in the coal.

9.4.2 Kawasaki Magnesium - Gypsum Double Alkali Process

In Japan, several double alkali processes have been developed that are based upon alkalis other than soda and that are tolerant to oxidation. Kawasaki Heavy Industries has developed a double alkali based on magnesium. It includes three major unit operations: absorption, oxidation and gypsum recovery, and magnesium hydroxide regeneration.

In the absorber, a slurry containing magnesium compounds removes SO_2 from the flue gas by reactions which form magnesium sulfite and magnesium bisulfite. The scrubbing slurry also contains calcium sulfate crystals which do not react with SO_2 in the flue gas.

In the oxidation and gypsum recovery section, the spent slurry from the absorber is oxidized by air, converting the magnesium sulfite and bisulfite to magnesium sulfate. Since calcium sulfate (gypsum) has a low solubility in water compared to magnesium sulfate, it is easily separated from the mother liquor by centrifuge. The gypsum from the centrifuge contains only about 10 percent moisture. The filtrate is a magnesium sulfate solution.

In the regeneration section, magnesium sulfate is converted to magnesium hydroxide by the addition of hydrated lime. The magnesium hydroxide and the calcium sulfate crystals formed in this step are then sent to the absorber as fresh slurry.

9.4.3 Magnesia Regenerable Process

The magnesia regenerable process uses a solution of magnesium hydroxide to absorb SO_2 and produce sulfuric acid as an end product. To minimize degradation of the regenerated magnesia, particulates and chlorides are removed ahead of the SO_2 absorber by a prescrubber.

In the absorber, an aqueous slurry of magnesium hydroxide and magnesium sulfite (pH range 6.5 to 8.5) is used to absorb the SO_2 according to the following equations:

$$Mg(OH)_2 + SO_2 \rightarrow MgSO_3 + H_2O \quad (1)$$

$$MgSO_3 + H_2O + SO_2 \rightarrow Mg(HSO_3)_2 \quad (2)$$

Some of the sulfite in the system is oxidized to sulfate. The magnesium sulfite and sulfate, which are formed as hydrate crystals, are centrifuged and dried. The dried crystals are calcined to produce solid MgO and an off gas of 7-9 percent SO_2. The MgO is recycled to the process and the SO_2 is converted to sulfuric acid.

9.4.4 Activated Charcoal Absorption Regenerable Process

Several vendors have offered activated charcoal processes which utilize physical absorption of SO_2. During the absorption, water vapor from the flue gas is also captured in the porous charcoal structure. It reacts with SO_2 and oxygen to form a dilute sulfuric acid solution. The absorption can take place at a flue gas temperature of 300 F.

The Bergbau Forschung process marketed in the United States by Foster Wheeler, recovers SO_2 by heating the charcoal to 1,000 F in contact with heated sand to produce the reaction

$$2\ H_2SO_4 + C \rightarrow 2\ SO_2 + 2\ H_2O + CO_2$$

Note that carbon is consumed by this recovery process. A pilot plant to test this technology was built at Gulf Power Company's Scholz Station in Florida. The facility included Foster Wheeler's Resox process for converting SO_2 to elemental sulfur. These test were plagued by mechanical problems. Larger scale tests are now being conducted in Germany with generally favorable, though preliminary, results.

The only activated charcoal process in commercial use, offered by Hitachi Ltd. of Japan, conducts regeneration by a four stage water wash. The product, a 60 percent H_2SO_4 solution, is too dilute for sale to sulfuric acid consumers. In Japan it is reacted with lime to form gypsum.

9.5 SUITABILITY AND STATUS OF THE FUTURE TECHNOLOGIES

Table 9-1 lists some of the advantages and disadvantages of the future technologies discussed above.

Regenerable processes are not practical for the small size installations at Navy bases because of the inherent process complexities and anticipated difficulties in marketing the by-product in small quantities.

Table 9-2 describes the commercial status of each of the six future technologies. Each process has the potential to become commercially available in the United States in the 1980s.

9.6 COSTS OF FUTURE TECHNOLOGIES

Capital costs for the first four processes in Table 9-1 are expected to be similar to those for current limestone, lime, and double alkali processes presented in Section 4.

Table 9-1

SUITABILITY OF FUTURE TECHNOLOGIES FOR USE AT NAVY BASES

Technology	Advantages	Disadvantages
Chiyoda Thoroughbred 121 Limestone Process	Process control simple Principal process steps performed in single vessel Includes integral forced oxidation to gypsum Low reagent cost Simple system	Potential fouling, corrosion not yet well defined SO_2 removal potential not yet verified Unknown geometric spacing and fluid mechanical features
Davy S-H Improved Lime Wet Scrubbing Process	Clear liquor scrubbing Includes forced oxidation to gypsum Organic acid gives pH control	Control and fouling problems of conventional wet scrubbers Employs lime which is more expensive than limestone
Spray Dryer/Fabric Filter Process with Lime Reagent	Easy process control Low process complexity Eliminates need for reheat Low water consumption Speed and ease of response to load swings	Low percent utilization of lime reagent Possible solids buildup May be suitable only for low sulfur coals
Kawasaki Magnesium Gypsum Double Alkali Process	Mg slurry has high concentration of dissolved reagent Allows complete oxidation to gypsum May be able to use limestone	Potential for fouling higher for slurry than for clear liquor scrubbing
Magnesia Regenerable Process	Produces by-product rather than waste	Consumes high grade energy to calcine
Activated Charcoal Processes	Dry rather than wet scrubbing Produces by-product rather than waste No reheat required	Consumes energy to recover SO_2, which then requires further conversion to sulfuric acid or sulfur German SO_2 recovery process involves fire hazards and consumes stoichiometric carbon Japan SO_2 recovery system yields low value dilute H_2SO_4 Highly corrosive

Table 9-2

COMMERCIALIZATION STATUS OF FUTURE TECHNOLOGIES

Technology	Status
Chiyoda Thoroughbred 121 Limestone Wet Scrubbing Process	• 20 megawatt scale unit demonstrated at Gulf Power Corporation's Scholz Station near Tallahassee, Florida, September 1978 - June 1979 EPRI announced in January 1980 that the tests were successful and called for a commercial project
Davy S-H Improved Lime Wet Scrubbing Process	• FGD unit for coal-fired 707 megawatt Weiher III power plant in Saarbruecken, Germany, was started up in the mid 1970s on 25 percent of the plant's flue gas, with additional FGD capacity planned in increments
Spray Dry/Fabric Filter Process with Lime Reagent	• A 20,000 scfm unit sold by Mikropul Corporation has operated since October 1979 for Strathmore Paper Company at Woronoco, Massachusetts
Kawasaki Magnesium-Gypsum Double Alkali Process	• A 180,000 scfm FGD system has been operating since the mid 1970s on an oil fired boiler at the Saidaiji plant of Japan Exlan Company • A 120,000 scfm system for the same company is operating at their Okazaki plant • A 6,000 scfm pilot unit has been tested on gas from a coal fired boiler
Magnesia Regenerable Process	• Philadelphia Electric Company has been testing an FGD system for a 120 megawatt coal fired boiler since 1978 • Two other U.S. utility companies operated experimental units briefly
Activated Charcoal Process	• A 250,000 scfm FGD unit sold by Hitachi Ltd has been operated by Tokyo Electric Power at Kashima since the mid 1970s

Section 10

SITE STUDY PRELIMINARIES

10.1 INTRODUCTION

Five operating scrubber facilities in the United States were examined in order to assess equipment reliability and maintainability as well as system efficiency and operability. The detailed analyses of the five facilities studied are given in Sections 11 to 15. This section presents certain comments that apply to all five facilities.

10.2 GENERAL DISCUSSION OF FACILITIES STUDIED

The facilities examined were as follows:

- The Chiyoda CT-121 limestone scrubber pilot plant at Gulf Power Company's Scholz Station near Tallahassee, Florida

- The Research-Cottrell/Bahco limestone scrubber at Rickenbacker AFB in Columbus, Ohio

- The Wellman-Lord Allied Chemical sodium sulfite-bisulfite demonstration plant at NIPSCO's Mitchell Station near Gary, Indiana

- The soda liquor scrubber at General Motors Corporation's St. Louis plant

- The FMC Corporation double alkali scrubber at Firestone Corporation's plant at Pottstown, Pennsylvania

All but one of the facilities are single train units. The General Motors St. Louis plant has two scrubbing trains, and often one of the trains serves as backup for the other when out of service.

There are few installed spare components in the facilities. Those provided include the following:

- Pumps for slurry, water, and return liquor in the Chiyoda CT-121 plant
- Diaphram sludge pumps in the Rickenbacker facility
- Miscellaneous (unidentified) pumps in the NIPSCO facility

Components requiring the most frequent maintenance in most plants are pumps and monitoring instrument probes. Usually, the instrument probes merely require cleaning which can be performed without shutting the FGD system down.

In all cases, efficient operation has only been realized recently.

10.3 DATA GATHERING

A visit was made to each facility studied. The following objectives were pursued during these visits:

- To gain a general understanding of the facility configuration
- To obtain answers to a questionnaire prepared for the data gathering effort (the questionnaire is reproduced as Appendix F)
- To collect any documents available, such as process and instrumentation diagrams
- To identify facility personnel for follow-up inquiry

In seeking answers to the questionnaire, special emphasis was given to collecting information on reliability and maintainability.

Published documents on the facilities were obtained whenever possible during the visit trips or in parallel investigations. A summary report on industrial scrubbers prepared for EPA by PEDCO, Inc. (Reference 11) provided some useful information.

10.4 CHARACTER OF THE ANALYSIS

The data gathering and analysis in this study were defined by time and funds. Examples of the limitations of the present study include the following:

- The reliability block diagram prepared for each facility reflects only the information available. It is not a complete diagram for the system
- Failure information available usually included major malfunctions and certain routine maintenance activities
- Information provided by operators was used when operating records were not readily available
- Bechtel estimates had to be made for failure frequencies and times to repair in many cases
- Outages used in the reliability analyses were limited to those in a suitable period after the "shakedown" period

10.5 QUALITY OF THE DATA

Data on equipment failures ranged from voluminous reports for FMC's scrubber at Firestone's Pottstown plant, to the most fragmentary data from the Chiyoda CT-121 representative. The variation in the volume of data was due to differences in repair philosophy (heavy versus minimal preventive maintenance), and in record keeping philosophy (documentation provided to the public domain versus cursory company private operating logs).

10.6 METHODOLOGY FOR RELIABILITY

As indicated in Section 2, reliability in this report is defined as the probability that a facility can operate continuously for one month without requiring a shutdown for maintenance. (This reliability measure does not take into account that the affected system can be started up again after the maintenance action. When this fact is to be taken into account, the best measure of performance is the inherent availability which is discussed later.)

However, reliability as defined above is quite useful as the probability of avoiding forced outages requiring immediate repair, and it is related to what was called "operability" in Section 7. If this reliability factor is high, there is less likelihood that a maintenance action will have to take place at an unscheduled time. Therefore, the demands on operating and maintenance personnel will be less severe.

For each facility studied, equipment failures were recorded in a failure mode and effects analysis (FMEA) table. The tabulated failures included failures that were corrected during emergency shutdowns and scheduled shutdowns, and failures that could be corrected without shutdown. Failures included all random failures indicated during the observation period. Failures were considered random if they were not directly related to errors in design or initial fabrication. Failures resulting from such erros were deemed "shakedown" failures. These failures were excluded from the FMEA.

For each failure, some frequency of occurrence was assigned. Most failures only occurred once in the history of the plant. Several recurred rather frequently. A few recurred very frequently (such as clogup of instruments, which necessiated routine cleaning).

From the recorded frequency of each failure, a mean time between failures (MTBF) was established. This was then converted to a most probable frequency as follows: Let i denote the ith failure and f_i the recorded frequency of the failure. The frequency f_i is recorded in the form

$$f_i = n_i/T_i \tag{10-1}$$

where T_i = the duration of the observation period in months

n_i = the number of failures in this mode during the observation period

Then a mean time between failures, t_i, can be calculated for the failure:

$$t_i = C^{-1}(n_i)\cdot T_i \tag{10-2}$$

Here $C^{-1}(n_i)$ is a multiplier given in Table 10-1.

The most probable frequency of failure, λ_i, is the reciprocal of t_i defined in (10-2):

$$\lambda_i = 1/t_i \tag{10-3}$$

The multiplier C^{-1} is derived from statistical tables in Reference 9. The tables assume that failures are of the random type which lead to an exponential dropoff with time in the probability of survival without failure. The multipliers C^{-1} are 50 percent one-sided confidence limits for the ratio t_i/T_i. This means that for fixed T_i, there is a 50 percent chance that the true mean time between failures is greater than t_i, and hence there is also a 50 percent chance that it is less than t_i. Thus t_i is a most probable value of the mean time between failures. Multipliers

for one or more failures are based on a chi square distribution, as explained in Reference 10. Note that Table 10-1 includes a multiplier for zero failures. This is used for each facility to find a mean time between failures for that aggregate of equipment components in series which did not fail during the period for which failures were recorded.

A reliability block diagram was drawn for each facility. Each diagram includes blocks showing general modules of the plant and blocks showing particular components that have failed. The diagrams show the general reliability relations between plant parts, and they are a tool for displaying the calculation of the reliability of the entire plant in terms of the reliability of individual components.

A component with a failure frequency λ_i has a realibility R_i that it will survive for time t without failure expressed as:

$$R_i = e^{-\lambda_i t} \tag{10-4}$$

Components are placed in series on a reliability block diagram when the failure of any one of them leads to failure of the system. Thus, an overall system reliability will be the product of the component reliabilities:

$$R = R_1 . R_2 ... R_k \tag{10-5}$$

Two components are placed in parallel on a reliability block diagram when one can act as a spare or backup for the other. Then the system will fail only when both the components in parallel are simultaneously nonfunctioning.

Table 10-1

MEAN TIME BETWEEN FAILURES AS A FUNCTION OF OBSERVATION TIME AND NUMBER OF FAILURES

Number, n, of Failures During Observation Period	Ratio $C^{-1}(n) = t/T$ Where t = Mean Time Between Failures (MTBF) and T = Duration of Observation Period*
0	1.44306
1	0.595901
2	0.373941
3	0.272340
4	0.214083
5	0.176357
6	0.149936
7	0.130399
8	0.115354
9	0.103434
10	0.0937385

Derived from Table A-1 on Page 24 of MIL-STD-690B (Reference 9) using 50 percent confidence levels. The ratios C^{-1} above are calculated from cumulative unit hours h given in Table A-1 by the formula

$$C^{-1} = 10^5/h,$$

since the mean time to failures for Table A-1 is 10^5 hours. Ratios above are reciprocals of multiples of the MTBF of the type of Table 5 in Reference 3.

*Note that the FMEA tables in subsequent chapters may contain failure modes with failure frequencies estimated by Bechtel, rather than frequencies taken from failure records. In each such case, the correct value to be used for $C^{-1}(n)$ is 1/n, rather than an entry from the right hand column above.

In this case, the system reliability for the pair is given approximately by:

$$R = 1 - (1-A_1)(1-A_2) \qquad (10\text{-}6)$$

where A_1 and A_2 are availabilities of the two components as defined later in this section. The availability is the fraction of time the component is available when called upon, and it serves as a "reliability with repair" mentioned in Reference 3.

In the diagrams for several of the facilities studied, components such as instrument probes are shown in parallel with a block having a label such as "failure tolerance operation." The reliability of this block in parallel has been assumed to be 1.0, since it is always possible to continue system operation for a short time while probes are being cleaned or replaced. When the reliability of one component in parallel is 1.0, the reliability of the system pair is 1.0, regardless of the reliability of the second component in parallel. Consequently, components so treated do not effect the overall system reliability.

The reliabilities calculated from these diagrams apply to the facilities studied. Two of the plants are pilot units with few installed spare components. Commercial plants would have some critical components with spares in parallel. The corresponding system reliabilities would be higher than for systems without installed spares.

10.7 METHODOLOGY FOR MAINTAINABILITY

Maintainability was defined in Section 2 as the probability that a work crew could correct a malfunction within the next immediate eight hours.

In each FMEA, an estimate is provided of the time t_{mi} required to correct a failure in the ith mode. This, together with the probable failure

frequency λ_i, permits calculation of the maintainability M as:

$$M = m/N \tag{10-7}$$

where

$$m = \sum_{i(t_{mi} \leq 8\ \text{hrs})} \lambda_i \tag{10-8}$$

$$N = \sum_{\text{All failures}} \lambda_i \tag{10-9}$$

Here, N is the total frequency of failure, and m is the frequency of failures that can be repaired in 8 hours.

The expected total repair hours per month, T_r, can be estimated as:

$$T_r = \sum_{\text{All failures}} \lambda_i t_{mi} \tag{10-10}$$

The mean time to repair (MTTR) can be calculated as:

$$MTTR = T_r/N \tag{10-11}$$

10.8 METHODOLOGY FOR AVAILABILITY

Availability was defined in Section 2 as the ratio of operating hours to the sum of operating hours plus maintenance hours. The most useful measure is the inherent availability. In this measure, the estimates of time for repair do not include administrative delays.

In reducing the repair data, a distinction is made between critical repairs and noncritical repairs. The system must be shut down while critical repairs are being made. The system does not need to be shut down while

noncritical repairs are being made. The downtime to make critical repairs is:

$$T_c = \sum_{\text{critical failures}} \lambda_i \, t_{mi} \qquad (10\text{-}12)$$

The availability A is then:

$$A = \frac{T_{oper}}{T_{oper} + T_c} \qquad (10\text{-}13)$$

where T_{oper} is the amount of time during the period in which the system is actually operating. Here both T_{oper} and T_c must be based on the same time period, such as one month.

Section 11

GULF POWER CHIYODA CT-121 LIMESTONE SCRUBBER

11.1 INTRODUCTION

A visit was made on June 28, 1979 to the Chiyoda Thoroughbred 121 (CT-121) scrubber installation at Gulf Power Company's Scholz Steam Plant near Tallahassee, Florida. Construction was completed in the summer of 1978, and the plant operated between August 30, 1978 and June 1979 to demonstrate a novel, potentially low-cost, high-reliability process.

Information presented in this section draws upon data collected during the visit and information taken from References 11 to 13.

11.2 GENERAL INFORMATION

Scholz Steam Plan is located in Sneads, Florida. The scrubber technology is the Jet Bubbling Reactor wet limestone process developed by Chiyoda Chemical Engineering and Construction Company of Japan and marketed in the United States by its wholly-owned subsidiary, Chiyoda International Corporation of Seattle, Washington. Chiyoda installed and operated the CT-121 unit with the cooperation of Gulf Power Company. It can process between 35,000 and 53,000 standard cubic feet per minute of flue gas. The upper flow rate corresponds to the output of a power plant generating approximately 23 megawatts of power.

The gas process by the CT-121 during tests was produced by a pair of 40 megawatt (nominal) Babcock and Wilcox pulverized coal boilers consuming Alabama Maxine coal containing 2.0 to 3.5 percent sulfur.

The jet bubbling reactor in the Chiyoda CT-121 at Scholz Station was built from the crystallizer vessel that was part of a precursor installation, a Chiyoda CT-101 FGD system that had been built and tested previously. The Venturi prescrubber upstream of the jet bubbling reactor was also a component of the previous process. It was used as a precooler for the CT-121 system.

Although the unit was built for a short demonstration, a service life of 30 years could be expected based on the materials used in construction.

Test operations on the unit between August 1978 and May 31, 1979 will be described in a report the Radian Corporation is preparing for the Electric Power Research Institute.

11.3 ECONOMICS

The capital cost of a comparable new (not retrofit) 23 megawatt unit would be 1,500,000 as erected (in 1979 dollars), according to Chiyoda representatives.

No information was provided on operation costs.

11.4 EFFICIENCIES

The process developer indicated that SO_2 removal greater than 90 percent was achieved when the pressure drop in the reactor exceeded 8 inches of water. Essentially 100 percent limestone utilization was achieved. Limestone is consumed at a rate of 1,500 pounds per hour. Waste gypsum is generated at the rate of 2,600 pounds per hour and is stacked without fixation.

Power consumption is 350 kilowatts, or 1.5 percent of the power that would be generated by a power plant of equivalent size. Water consumption is 20 to 25 gallons per minute. No steam is required.

11.5 CONFIGURATION

A single scrubbing train is provided. No provision for excess capacity has been made. Excess flue gas is vented through the power stack without treatment.

Spared system components include limestone slurry makeup pumps, waste removal pumps, water makeup pumps, and pond return liquid pumps. Pump packing and pH meter electrodes are kept on hand as spare parts.

11.6 OPERATIONAL LIFE PROFILE

Possible conditions encountered during the service life which define the "operational life profile" include:

- Ambient temperatures between $15^{\circ}F$ and $105^{\circ}F$
- Hurricane winds
- A concentration of up to 6,000 parts per million dissolved chlorides in the absorbent slurry
- Coal sulfur levels between 2 and 4 percent
- Reactor slurry pH between 4 and 6
- A concentration of slurry solids between 10 and 30 weight percent
- Continuous operation of boiler and scrubber

Chiyoda claims the scrubber is not sensitive to entrained solids. At Scholz Station an electrostatic precipitator was already attached to the boiler system when the Chiyoda units were added.

11.7 RELIABILITY

Table 11-1 is a failure mode and effects analysis (FMEA) prepared from information collected. For each failure mode the table shows the cause, the effect on the system, and remarks about stress levels and requirements

for shutdown. The table also shows the reported or estimated time required to correct each malfunction, its frequency of occurrence, and the mean time between failures (MTBF) computed from the frequency using Table 10-1.

Figure 11-1 is a simplified reliability block diagram for the Scholz Station CT-121 scrubber. The diagram shows the components that failed as well as other components to present a complete reliability picture of the facility. From the reliability shown below each block, a total system reliability, R, can be computed to be:

$$R = 0.7534 \tag{11-1}$$

R is the probability that the Scholz Station CT-121 scrubber can operate continuously for one month without a forced shutdown. It corresponds to an expectation of one forced shutdown every 3 months. As stated in Section 10, the "reliability" defined in this way is more a measure of what the Navy calls "operability," or ease of operation, than it is a measure of reliable operation for meeting environmental standards continuously over a period of time. This is because the system can be restarted after repair of a malfunction causing shutdown. The best measure for reliable operation from this point of view is the availability discussed later in this section.

11.8 MAINTAINABILITY

Maintainability as a mathematical measure was defined in Sections 2 and 10 as the probability that a work crew could correct a malfunction within a single 8-hour work period.

Repair times are given in Table 11-1 for each failure made. Using equations (10-7) to (10-8), N, the total frequency of failures 1 to 11 in Table 11-1, can be calculated to be 5.53 per month; m, the frequency of failures that can be repaired in an 8-hour work period, is 5.39; the maintainability M is the ratio m/N, and

$$M = 97.4 \text{ percent} \tag{11-2}$$

Failure Number	Component	Failure Mode (Subcomponent Failing)	Cause	Effect of Failure on System	
1	Booster fan	Rotor balancing, bearing change	wear	System becomes inoperative	S A
2	Reactor	Mixer shaft	wear	Extensive future equipment damage if not corrected	S A
3	Air blower	Bearing change	wear	System remains operative for short duration	S A
4	Limestone slurry make-up pumps	Mechanical seals	wear	Extensive future equipment damage if not repaired	S A
5	Limestone slurry make-up pumps	Drive belts	wear	Component becomes inoperative	S A
6	Waste slurry disposal pumps	Mechanical seals	wear	Extensive future equipment damage if not repaired	S A
7	Waste slurry disposal pumps	Drive belts	wear	Component becomes inoperative	S A
8	Pond return liquor pump	Packing	wear	Extensive future equipment damage if not corrected	S A
9	Reactor slurry pH meter	Glass electrode	Coating by slurry solids	System function more inconvenient	S A
10	Radiation type slurry density meter	Pipe internal surface	Coating by slurry solids	System function more inconvenient	S A
11	Magnetic type slurry flow meter	Magnetic flow sensor	Coating by slurry solids	System function more inconvenient	S A

Notation: * = Bechtel estimate
NI = No information available

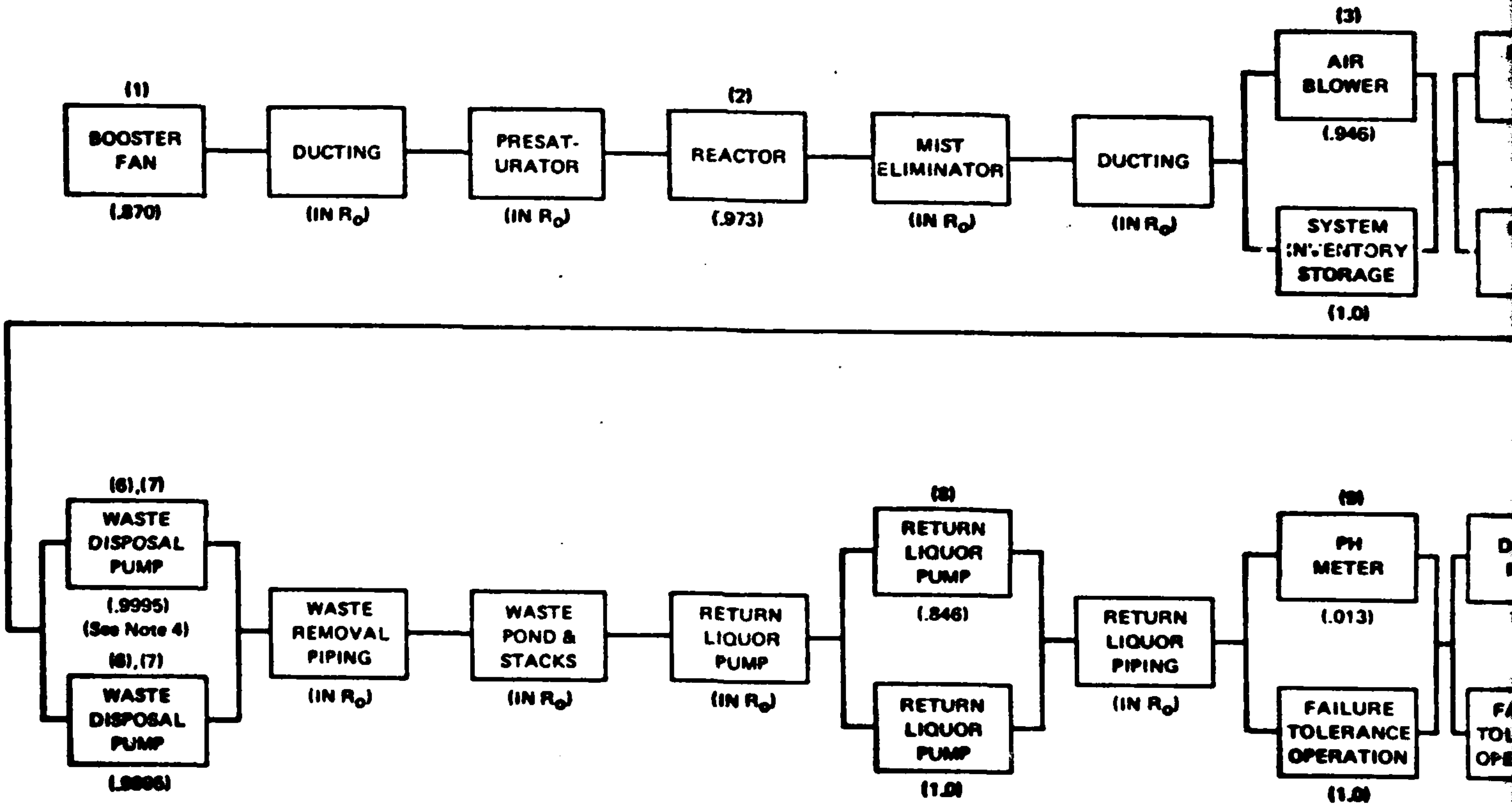
S = Stress level
A = Action taken

Table 11-1

FAILURE MODE AND EFFECTS ANALYSIS (FMEA) —
CHIYODA THOROUGHBRED 121 SCRUBBER,
GULF POWER SCHOLZ STATION, SNEADS, FLA
PERIOD: 11/15/78 – 6/29/79

f Failure on System	Remarks	Total Outage Hours	Failure Frequency, Failures Period	Mean Time Between Failures (MTBF), Months
ecomes inoperative	S = NI A = System shutdown required for repair	12*	1/yr*	7.2
future equipment f not corrected	S = NI A = Repair performed during scheduled system shutdown	8*	1/3 yrs*	36
emains operative t duration	S = NI A = System shutdown not required because of temporary surge tolerance capacity of the reactor slurry inventory	6*	1/30 mos	18
future equipment f not repaired	S = NI A = Repair performed with spare pump in operation	2	1/yr*	12
t becomes ive	S = NI A = Repair performed with spare pump in operation	1*	1/6 mos*	6
future equipment f not repaired	S = NI A = Repair performed with spare pump in operation	2	1/yr*	12
t becomes ive	S = NI A = Repair performed with spare pump in operation	1*	1/6 mos*	6
future equipment f not corrected	S = Normal A = System shutdown not required due to surge tolerance of reactor inventory	1	1/6 mos*	6
unction more lent	S = Normal A = Glass electrode removed, cleaned, calibrated and reinstalled. System shutdown not required.	1*	1/wk*	.23
unction more lent	S = Normal A = Cleaning performed during scheduled shutdown	6*	1/3 yrs*	36
unction more lent	S = Normal A = Sensor surface cleaned during scheduled shutdown. Meter calibrated electronically	2*	1/6 mos*	6

s level
n taken



R = Combined System reliability (probability of operating for one month without shutdown) = .7534

Notes:

1. Numbers in parentheses on top of blocks denote failure items from FMEA (Table 11-1).
2. Number in parentheses below each block is the reliability of the block.
3. The expression "(In R_o)" indicates that the reliability for that block is part of a series of blocks with combined reliability R_o. The value of R_o is 0.8909, corresponding to zero failures in 6 months.
4. Reliabilities for the two items in parallel are reliabilities with repair.

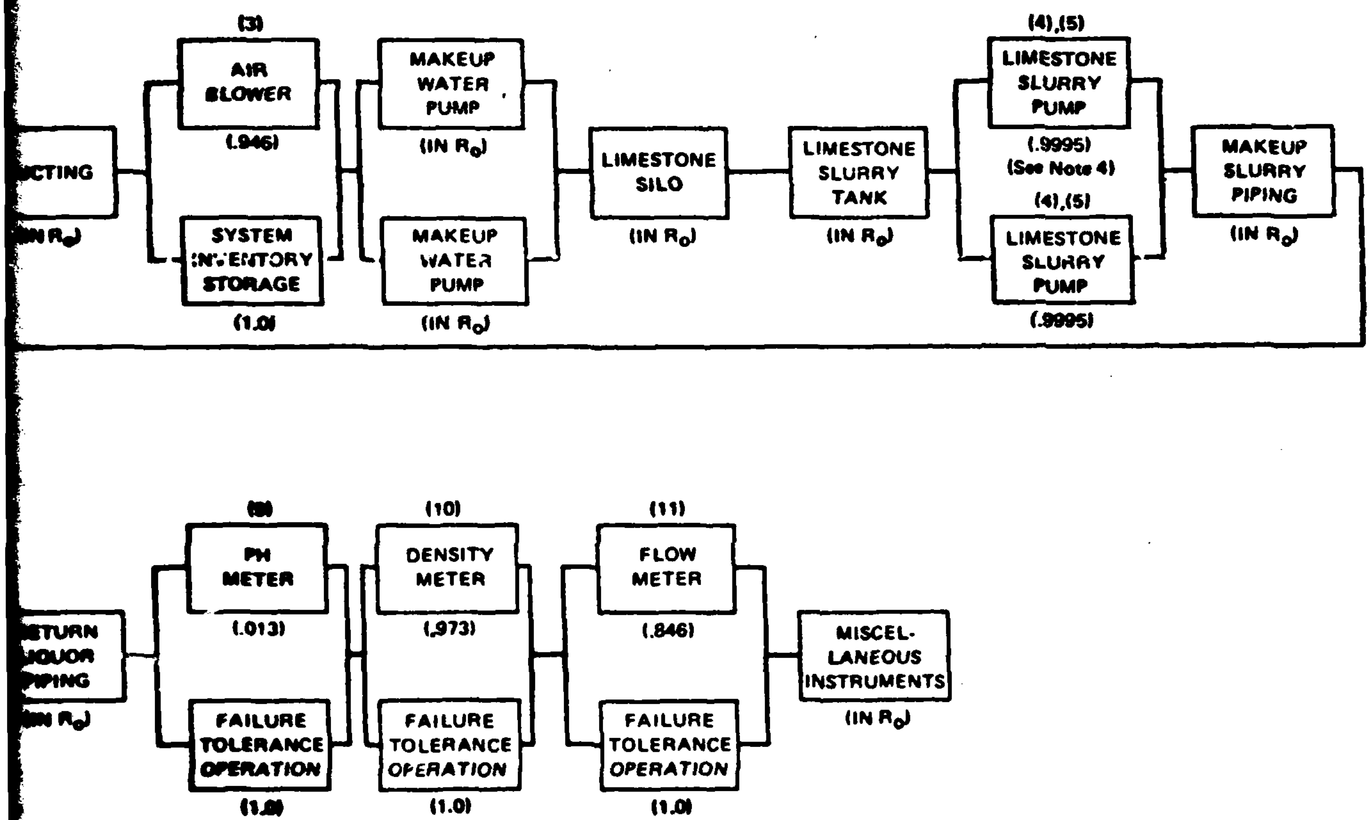


Figure 11-1
RELIABILITY BLOCK DIAGRAM—
CHIYODA THOROUGHBRED 121 SCRUBBER,
GULF POWER SCHOLZ STATION, SNEADS, FL.

Other parameters provide information about the maintainability of the scrubber. The expected total repair hours per month, T_r, can be computed by summing up the products of the failure frequency and the expected repair time for each failure mode, according to equation (10-10). The result is:

$$T_r = 7.90 \quad \text{hours per month} \qquad (11\text{-}3)$$

The mean time to repair (MTTR) is the ratio T_r/N. This is

$$\text{MTTR} = 1.43 \quad \text{hours per failure} \qquad (11\text{-}4)$$

11.9 AVAILABILITY

The availability was defined in Sections 2 and 10. It measures the fraction of time the FGD system performed as required during a period. It is the best measure of the ability of a scrubber to perform "reliably." The availability is calculated from the frequencies and the times to repair for critical failure modes.

Critical failure modes can be defined as failure modes of components which do not have backup components in parallel. These can be readily identified on the reliability block diagram (Figure 11-1). A failure in a critical mode will require a forced system shutdown whereas noncritical failures will not. The expected total critical repair time, T_c, was defined in equation (10-12).

The availability, A, is derived from T_c according to equation (10-13). Values for T_c and A for the CT-121 system at Scholz Station are as follows:

$$\left.\begin{array}{lll} T_c & = 1.90 & \text{hours per month} \\ A & = 99.7 & \text{percent} \end{array}\right\} \qquad (11\text{-}5)$$

In deriving the availability above, contributions have been ignored from failures of components with blocks in parallel on the reliability block diagram. This is because the availability of a pair of blocks in parallel approaches 100 percent. This can be shown for the waste disposal pump in Figure 11-1. The availability is 0.9995 for a single pump (using the data from Table 11-1). The availability of a pair of pumps in parallel is given approximately by:

$$A_{pair} = 1 - (1 - A_{single})^2 = 0.9999997$$

11.10 COMMENTS ON R AND M CALCULATIONS

The following considerations are appropriate in interpreting the reliability, maintainability, and availability values calculated above:

- The failures in Table 11-1 were those acknowledged by the process developer, Chiyoda. The complete performance history on the CT-121 scrubber being compiled by the Radian Corporation was not available to the public at the time this report was written. Judgment on the Chiyoda CT-121 should be reserved until a revised analysis based on Radian's data is made

- The 9-month analysis period for the calculations is relatively short. A longer demonstration history would permit a more reliable analysis

- The values calculated above for the CT-121 are excellent, and indicate a low maintenance, easily operable system

11.11 OPERATION AND MAINTENANCE FACTS

Two operators per shift, (three shifts per day) were assigned in the CT-121 demonstration at Scholz Station. For a full-scale commercial plant, Chiyoda representatives estimate a need for one outdoor FGD system operator plus 20 percent of a boiler room control board operator each shift. In addition, during the day shift each week, maintenance could be performed with 20 percent of an electrical technician's time, 20 percent of a mechanical technician's time, and 40 percent of a laborer's time.

The CT-121 does not have any operations that require close tolerance manual control. The efficiency of SO_2 removal can be controlled by monitoring reactor pH and manually adjusting limestone slurry addition.

The CT-121 does not have any operations requiring quick operator action to avert malfunction or equipment damage.

The following preventative and scheduled maintenance activities indicated by Chiyoda are:

- Lubrication of rotating equipment such as pumps, blower, and agitators by operator according to equipment manufacturer's schedule
- pH meter values checked daily by laboratory analysis of grabbed samples
- Calibration of slurry flow meters during scheduled shutdowns

The "shakedown" period included two shutdowns to repair the oxidation blower that had been damaged during storage prior to installation.

Section 12

RICKENBACKER AFB R-C/BAHCO LIME/LIMESTONE SCRUBBER

12.1 INTRODUCTION

The scrubber installation at Rickenbacker AFB was visited on July 10 and 11, 1979. The U.S. Air Force had selected Rickenbacker AFB as the demonstration site for a lime slurry scrubber for coal-fired, industrial-sized boilers. The plant was started up in March 1976. In the spring of 1977 the plant was converted for use of powdered limestone as the reagent feed.

Information presented in this section has drawn upon data collected during the visit, and information taken from References 11 and 14 to 16.

12.2 GENERAL INFORMATION

The facility is owned and operated by the U.S. Air Force at Rickenbacker Air Force Base in Lockbourne, Ohio, a suburb of Columbus. The scrubber manufacturer is Research-Cottrell, Inc., P.O. Box 750, Bound Brook, New Jersey 08805. The technology used was developed by A. B. Bahco Ventilation Company of Sweden. Research-Cottrell acquired a license from Bahco in 1971. The installation at Rickenbacker AFB is the first Bahco unit in the U.S. Installation was completed in March 1976.

The scrubber has the capacity to process 108,000 actual cubic feet per minute of flue gas entering at $475^{o}F$. This corresponds to approximately 21 megawatts electric or 210×10^{6} Btu/hr of coal boiler feed. It has an unusually high turn down ratio of 10 to 1. The boilers are stokers which typically consume 35,000 tons of coal per year. Upstream of the scrubber

is a mechanical collector which removes 75 to 80 percent of the particulates in the flue gas.

The R-C/Bahco system utilizes an absorber vessel with two Venturi stages for countercurrent contacting. Their Venturi stage creates droplets by passing the gas at high velocity across the surface of the liquid. The droplets remove SO_2 from the flue gas and are then collected higher in the absorber.

When the Air Force desired a demonstration of lime or limestone scrubbing at one of its installations, Rickenbacker AFB was selected because it had coal-fired boilers and because it was seeking a modification of its boiler plant at the time of deliberation. It was also anticipated that SO_2 emission standards would be imposed on industrial installations in Ohio. For compliance, coal-burning systems would either have to pay premium prices for low sulfur coal, or install SO_2 removal requipment.

The installation of the FGD system permitted the use of high sulfur coal while meeting the SO_2 regulation in force. Personnel at Rickenbacker AFB compute the unit cost of operating their scrubber to be $6.81 per ton of high sulfur coal. In contrast, the premium for compliance low sulfur coal is approximately $14 per ton. Thus they save approximately $7 per ton on 35,000 tons per year, or $250,000. The capital investment was $2,000,000. Using the zero inflation discounted cash flow methods of Reference 4, it can be shown that the savings will pay back the investment in approximately 13 years.

The scrubber has reduced SO_2 emissions from the boiler system from 1,800 tons per year to 840 tons per year and particulate emissions from 2,400 tons per year to 70 tons per year. Rickenbacker is changing boiler combustion controls in an effort to reduce submicron emissions. The old and inefficient boilers at Rickenbacker emit an unusually large quantity of submicron particles which are not removed by the scrubbing system.

The sludge produced by the scrubber is disposed of in an on-site lined pond.

The FGD system was designed to last 20 years. The pond has been designed to last 5 years. As of July 1979, the facility had been in service for 3 years and 3 months. The boiler fuel is an Ohio bituminous coal containing 2.9 to 3.8 percent sulfur. The heating plant consists of five old units rated at 31 x 10^6 Btu/hr output and one new unit rated at 60 x 10^6 Btu/hr output. All are stoker systems. The heat output is in the form of hot water or steam. The flue gas from all six units flows to a common duct leading to the scrubber system.

12.3 ECONOMICS

The capital cost of the facility was $2,000,000. The design phase cost $100,000. The following information from Reference 15 gives a breakdown of the annual costs:

Operating Labor (0.25 man/shift, $8.48/hr)	$ 17,553
Supervision (25% of operating labor)	$ 4,388
Maintenance Labor	$ 17,000
Maintenance Material	$ 4,000
Limestone (0.4 tons/hr, $15.16/ton)	$ 50,210
Water (30 gpm, $\$0.54/10^3$ gas)	$ 8,048
Electricity (518 kW avg, $0.032/kW hr)	$137,249
Total Annual Cost	$238,448

The annual cost for maintenance is $21,000. The balance of $217,448 can be called operating costs.

12.4 EFFICIENCIES

When lime is the reagent, the SO_2 removal efficiency exceeds 90 percent (the design removal). When limestone is used as the reagent, removal efficiencies up to 92 percent are possible when the percentage of excess reagent and the rate of liquor circulation are set high enough. Current

operation gives 70 to 85 percent removal. Local regulations require only 68 percent removal.

In limestone slurry scrubbing, about 3,300 tons per year of limestone are consumed, or about one ton of limestone per ton of coal burned. The limestone utilization is about 75 percent.

The scrubber system consumes approximately 518 kilowatts on the average, or 2.5 percent of the power output of a 21 megowatt power plant.

The scrubber system does not include reheating the cleaned gas, so no steam or fuel is required to operate the scrubber in normal weather. In cold weather, heat tracing on various lines is used to prevent freezing, since the FGD system is outdoors.

12.5 CONFIGURATION

The scrubber system includes one FGD train. Since the design and actual maximum capacity are the same, there is no excess capacity provided. The only components spared are the waste disposal pumps and their associate transfer lines.

Critical parts kept on hand include diaphragms for the waste disposal pumps and rubber liners and impellers for the first- and second-stage centrifugal slurry pumps. Also, SO_2 and pH instrument probes are kept on hand.

12.6 OPERATIONAL LIFE PROFILE

The conditions encountered during the life of the scrubber serve to define its "operational life profile" which is familiar in reliability and maintainability engineering.

The scrubber at Rickenbacker AFB can operate with ambient temperatures between 98 and -10°F, and with wind chill factors of -50°F.

The coal sulfur level ranges between 2.9 and 3.8 percent. No coal chemical contaminants have an adverse effect on the scrubber. However, to avoid the buildup of chlorides, water is not returned to the scrubber from the waste disposal pond.

The flue gas rate can be between 30 and 58 x 10^3 standard cubic feet per minute. However, air to substitute for flue gas is automatically sucked in if boiler flue gas flows drop below this range, so substantially lower flue gas rates can be tolerated.

The boilers and scrubber operate 24 hours a day, all year long.

The R-C/Bahco technology is not detrimentally affected by particulate carry-over into the scrubber. The scrubber at Rickenbacker AFB is designed to remove 20 to 25 percent of the particulates generated in the boilers, since the mechanical collector upstream removes 75 to 80 percent of the particulates. The scrubber system would eventually have to be shut down if a failure of the mechanical collector occurred.

During a recent typical year, the scrubber system was shut down for 300 hours of nonelective maintenance and was shut down for 16 days of scheduled maintenance.

The system was converted from lime to limestone reagent in the spring of 1977 to reduce reagent costs and also to avoid using the lime slaker, which had been requiring a considerable amount of operator and maintenance attention.

12.7 RELIABILITY

The initial "shakedown" or "burn in" stage appears to have been completed by about May 1977. Up to that time, nonrecurring design and equipment

defects had caused a series of outages. The period from September 1977 to June 1979 was selected for analysis of failures that were considered random.

Table 12-1 is a failure mode and effects analysis (FMEA) tabulation for the R-C/Bahco scrubber at Rickenbacker AFB showing 32 failure modes. For each failure mode, the table shows the cause, the effect on the system, and remarks about stress levels and requirements for shutdown. The table also shows the reported or estimated time to correct each malfunction, its frequency of occurrence, and the mean time between failures (MTBF) calculated from the frequency using Table 10-1.

Figure 12-1 is a simplified reliability block diagram for the scrubber installation at Rickenbacker AFB. The diagram shows components that failed, as well as other components to present a complete reliability picture of the facility. From the reliability shown below each block, a total system reliability R can be computed to be

$$R = 0.2353 \text{ (Rickenbacker FGD plant)} \qquad (12\text{-}1)$$

This is the probability that the scrubber at Rickenbacker AFB can operate continuously for one month without a forced shutdown.

A commercial installation could be designed with a reliability higher than computed above, if each slurry circulation pump had a spare installed in parallel. Then the probability R of operating for a month without a forced shutdown would be

$$R = 0.638 \text{ (plant with spare pumps)} \qquad (12\text{-}2)$$

As stated in Section 10, the "reliability" defined in this way is more of a measure of what the Navy calls "operability," or ease or operation, than a measure of reliable operation for meeting environmental standards continuously over a period of time. This is because the system can be restarted after

Failure Number	Component and Function in System	Failure Mode (Subcomponent Failing)	Cause	Effect of Failure on Sys
1	Booster fan supplying flue gas and air mixtures to the scrubber	Fan housing weld	NI	Safety hazard created
2	First stage slurry circulation pump for the scrubber internal hold tank	Rubber liner of pump casing	NI	Extensive future damage o component if not repaired
3	First stage slurry circulation pump for the scrubber internal hold tank	Rubber lined impellor	Erosion by abrasive slurry solids	Extensive future damage o subcomponent if not repaired
4	First stage slurry circulation pump for the scrubber internal hold tank	Sleeve	Erosion	Extensive future damage o component if not repaired
5	First stage slurry circulation pump for the scrubber internal hold tank	Throat bushing	Erosion	Extensive future damage o component if not repaired
6	First stage slurry circulation pump for the scrubber internal hold tank	Packing	Erosion	Extensive future damage o component if not repaired
7	First stage slurry circulation pump for the scrubber internal hold tank	Drive belts	Wear	System function more inconvenient

Notation:
* = Bechtel estimate
NI = Detailed information not available
S = Stress level
A = Action taken

Table 12-1

FAILURE MODE AND EFFECTS ANALYSIS (FMEA) — R-C/BAHCO LIME/LIMESTONE PROCESS RICKENBACKER AFB, OHIO PERIOD: 9/77 — 6/79

...ause	Effect of Failure on System	Remarks	Total Outage Hours	Failure Frequency, Failures/Period	Mean Time Between Failures (MTBF), Months
NI	Safety hazard created	S = NI A = System shutdown for component repair	16*	1/33 mos	19.7
NI	Extensive future damage of component if not repaired	S = NI A = Discovered and repaired during scheduled system shutdown	16	1/36 mos	21.4
...on by ...ive ...y solids	Extensive future damage of subcomponent if not repaired	S = NI A = Discovered and repaired during scheduled system shutdown	16*	1/38 mos	22.6
...on	Extensive future damage of component if not repaired	S = NI A = Discovered and repaired during scheduled system shutdown	8	1/21 mos	12.5
...on	Extensive future damage of component if not repaired	S = Normal A = Discovered and repaired during scheduled system shutdown	6	1/38 mos	22.6
...on	Extensive future damage of component if not repaired	S = Normal A = Packing replaced. System shutdown not required because first stage hold tank has tolerance for temporary slurry inhomogeneity	1	1/3 mos	2.6
	System function more inconvenient	S = Normal A = Immediate belt replacement necessary. System shutdown not required because first stage hold tank has tolerance for temporary slurry inhomogeneity	1	1/6 mos	4.5

Failure Number	Component and Function in System	Failure Mode (Subcomponent Failing)	Failure Cause	Effect of Failure on System
8	Second stage slurry recycle pump to circulate slurry through the scrubbing system	Rubber liner of pump casing	NI	Extensive future damage of component if not repaired
9	Second stage slurry recycle pump to circulate slurry through the scrubbing system	Sleeve	Erosion	Extensive future damage of component if not repaired
10	Second stage slurry recycle pump to circulate slurry through the scrubbing system	Packing	Erosion	Extensive future damage of component if not repaired
11	Second stage slurry recycle pump to circulate slurry through the scrubbing system	Throat bushing	Erosion	Extensive future damage of component if not repaired
12	Second stage slurry recycle pump to circulate slurry through the scrubbing system	Drive belt	Wear	System becomes inoperative
13	Sludge pumps for sludge transfer from thickener or sump to pond	Neoprene diaphragm.	Wear	System function more inconvenient

Notation:
* = Bechtel estimate
NI = Detailed information not available
S = Stress level
A = Action taken

Table 12-1 (Continued)

Cause	Effect of Failure on System	Remarks	Total Outage Hours	Failure Frequency, Failures Period	Mean Time Between Failures (MTBF), Months
	Extensive future damage of component if not repaired	S = NI A = Discovered and repaired during scheduled system shutdown	16	1/36 mos	21.4
	Extensive future damage of component if not repaired	S = NI A = Discovered and repaired during scheduled system shutdown	8	1/21 mos	12.5
	Extensive future damage of component if not repaired	S = Normal A = Packing replaced. System shutdown required because slurry circulation is stopped during repair period	1	1/3 mos	2.6
	Extensive future damage of component if not repaired	S = Normal A = Discovered and repaired during scheduled system shutdown	6	1/38 mos	22.6
	System becomes inoperative	S = Normal A = New belts installed. System shutdown required because slurry circulation is stopped during repair period. (Repair might be performed during scheduled system shutdown if inspection of belts indicate near-failure condition)	1	1/6 mos	4.5
	System function more inconvenient	S = Normal A = Diaphragm replaced. System shutdown not required because of 100 percent pump standby capacity and temporary surge tolerance of both the thickener and sump	3	8/yr/pump	1.4/pump

Failure Number	Component and Function in System	Failure Mode (Subcomponent Failing)	Failure Cause	Effect of Failure on System
14	Sludge pumps for sludge transfer from thickener or sump to pond	"O" ring	Wear	System function more inconvenient
15	Lime slaker/limestone mixer	Paddle shaft motor	NI	System becomes inoperable
16	Lime slaker/limestone mixer	Grit conveyor motor	NI	System becomes inoperable
17	Lime slaker/limestone mixer	Paddle shaft bushing	Wear	System function more inconvenient
18	Lime slaker/limestone mixer	Paddle shaft belts	Wear	System function more inconvenient
19	Reagent feed rate control	Weight belt mechanism	Wear	System becomes inoperable if not repaired
20	Flue gas flow meter	Annubar type flow element	Plugging with fly ash	System function more inconvenient
21	Slurry flow meters: • First stage recycle • Second stage recycle • Thickener feed	Magnetic flow sensors	Sensors coated with solids	System function more inconvenient

Notation:
* = Bechtel estimate
NI = Detailed information not available
S = Stress level
A = Action taken

Table 12-1 (Continued)

ct of Failure on System	Remarks	Total Outage Hours	Failure Frequency, Failures/Period	Mean Time Between Failures (MTBF), Months
em function more nvenient	S = Normal A = "O" ring replaced. System shutdown .... (same as above for neoprene diaphragm)	3	2/yr/pump	1.4/pump
em becomes inoperable	S = Normal A = Motor replaced during system shutdown after 14 months of operation (May 1977)	11	1/39 mos	23.2
em becomes inoperable	S = Normal A = Conveyor was replaced during scheduled maintenance after 12 months of operation (March 1977)	8	1/39 mos	23.2
em function more nvenient	S = Normal A = Bushings replaced. System shutdown .... (same as below for paddle shaft belts)	2	1/yr	7.2
em function more nvenient	S = Normal A = Belts replaced. System shutdown not required because lime dissolving tank has tolerance for short-term slaked lime inventory	1	1/18 mos	10.7
em becomes inoperable ot repaired	S = Normal A = Weight belt mechanism replaced during scheduled maintenance	48*	1/39 mos	23.2
em function more nvenient	S = Normal A = Flow element removed for routine cleaning	4	2/mo	0.37
m function more venient	S = Normal A = Sensor surface cleaned during scheduled shutdowns; meters calibrated electronically	2	1/6 mos, ea	3.6

1 x 2

Failure Number	Component and Function in System	Failure Mode (Subcomponent Failing)	Failure Cause	Effect of Failure on Syste
22	SO_2 sensors • Inlet sensor • Outlet sensor	Untreated and treated flue gas sample probes	Temporary plugging	System function more inconvenient
23	SO_2 sensors • Inlet sensor • Outlet sensor	Untreated and treated flue gas sample probes	Permanent plugging	System function more inconvenient
24	SO_2 analyzer	Panel circuit board	NI	System function more inconvenient
25	Slurry pH meters (lime dissolver tank, first stage level tank)	Glass electrode	Coating by slurry solids	System function more inconvenient
26	Slurry pH meters (lime dissolver tank, first stage level tank)	Glass electrode	Breakage	System function more inconvenient
27	Radiation type slurry density meter	Radiation shield shutter shaft	NI	System function more inconvenient
28	Radiation type slurry density meter	Amplifier board	NI	System function more inconvenient
29	Pond line wash system	Timer	NI	System function more inconvenient
30	Miscellaneous instruments (10*)	Printed circuit boards	NI	System function more Inconvenient

Notation:
* = Bechtel estimate
NI = Detailed information not available
S = Stress level
A = Action taken

Table 12-1 (Continued)

se	Effect of Failure on System	Remarks	Total Outage Hours	Failure Frequency, Failures/Period	Mean Time Between Failures (MTBF), Months
	System function more inconvenient	S = Normal A = Probes cleaned from removal solids buildup. System shutdown not required	1	1/3 days, ea	.060
	System function more inconvenient	S = Normal A = Probes replaced. System shutdown not required	1	1/12 mos, ea	7.2
	System function more inconvenient	S = Normal A = Circuit board replaced. System shutdown not required	1	1/36 mos, ea	21.4
ids	System function more inconvenient	S = Normal A = Glass electrodes removed, cleaned, and calibrated. System shutdown not required	1	1/2 wks, ea	0.30
	System function more inconvenient	S = Normal A = Glass electrodes replaced. System shutdown not required	1	1/yr, ea	7.2
	System function more inconvenient	S = NI A = Removed during scheduled shutdown. System shutdown required	NI	1/39 mos	23.2
	System function more inconvenient	S = NI A = Replaced. System shutdown not required	1	1/36 mos	21.4
	System function more inconvenient	S = NI A = Timer replaced. System shutdown not required	2	1/36 mos	21.4
	System function more Inconvenient	S = NI A = Circuit boards replaced. System shutdown not required	1	(1/yr)*	1.2

Failure Number	Component and Function in System	Failure Mode (Subcomponent Failing)	Failure Cause	Effect of Failure o
31	Slurry liquid level blowdown systems	Rubber pinch valves	Erosion	Not effected.
32	Waste slurry disposal	Piping to pond	Plugging with suspended solids	Not effected. 100 standby pipe capaci

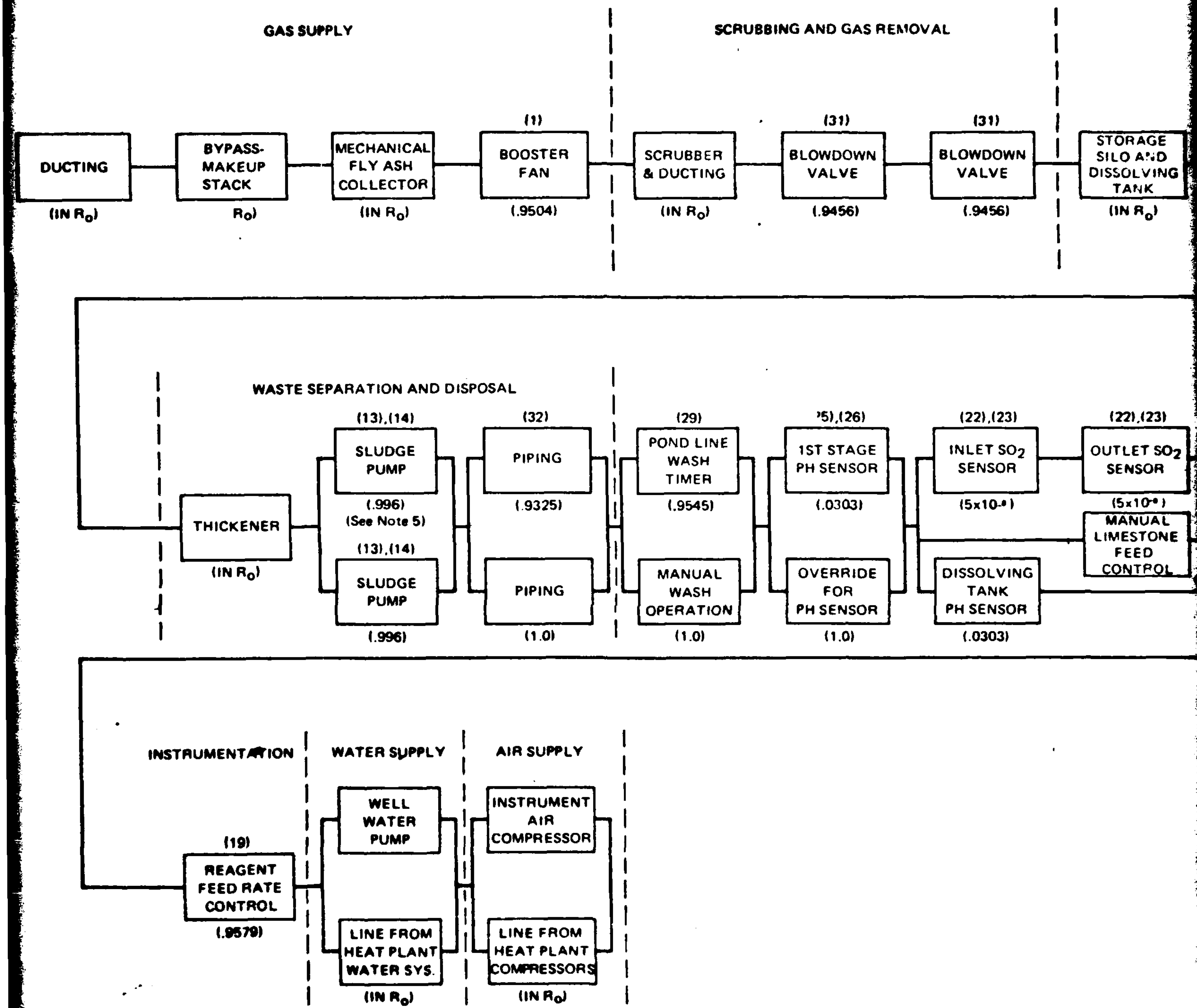
Notation:

* = Bechtel estimate
NI = Detailed information not available.
S = Stress level
A = Action taken

Table 12-1 (Continued)

Cause	Effect of Failure on System	Remarks	Total Outage Hours	Failure Frequency, Failures/Period	Mean Time Between Failures (MTBF), Months
	Not effected.	S = Normal A = Two valves replaced during scheduled shutdown	4	1/30 mos ea	17.9
g with ed	Not effected. 100 percent standby pipe capacity	S = NI A = Pipe cleaned	10	1/2 yrs	14.3

146



R = Combined system reliability (probability of operating for one month without shutdown) = 0.2353.

Notes.

1. Numbers in parentheses on top of blocks denote failure items from FMEA (Table 12-1).
2. Number in parentheses below each block is the reliability of the block.
3. The expression "(In R_o)" indicates that the reliability for that block is part of a series of blocks with combined reliability R_o. The value of R_o is 0.9824, corresponding to zero failures in 39 months.
4. Component failures indicated can be made in two hours or less and do not require system shutdown because of temporary tolerance block in parallel.
5. Reliabilities for two diaphragm pumps in parallel are reliabilities with repair.

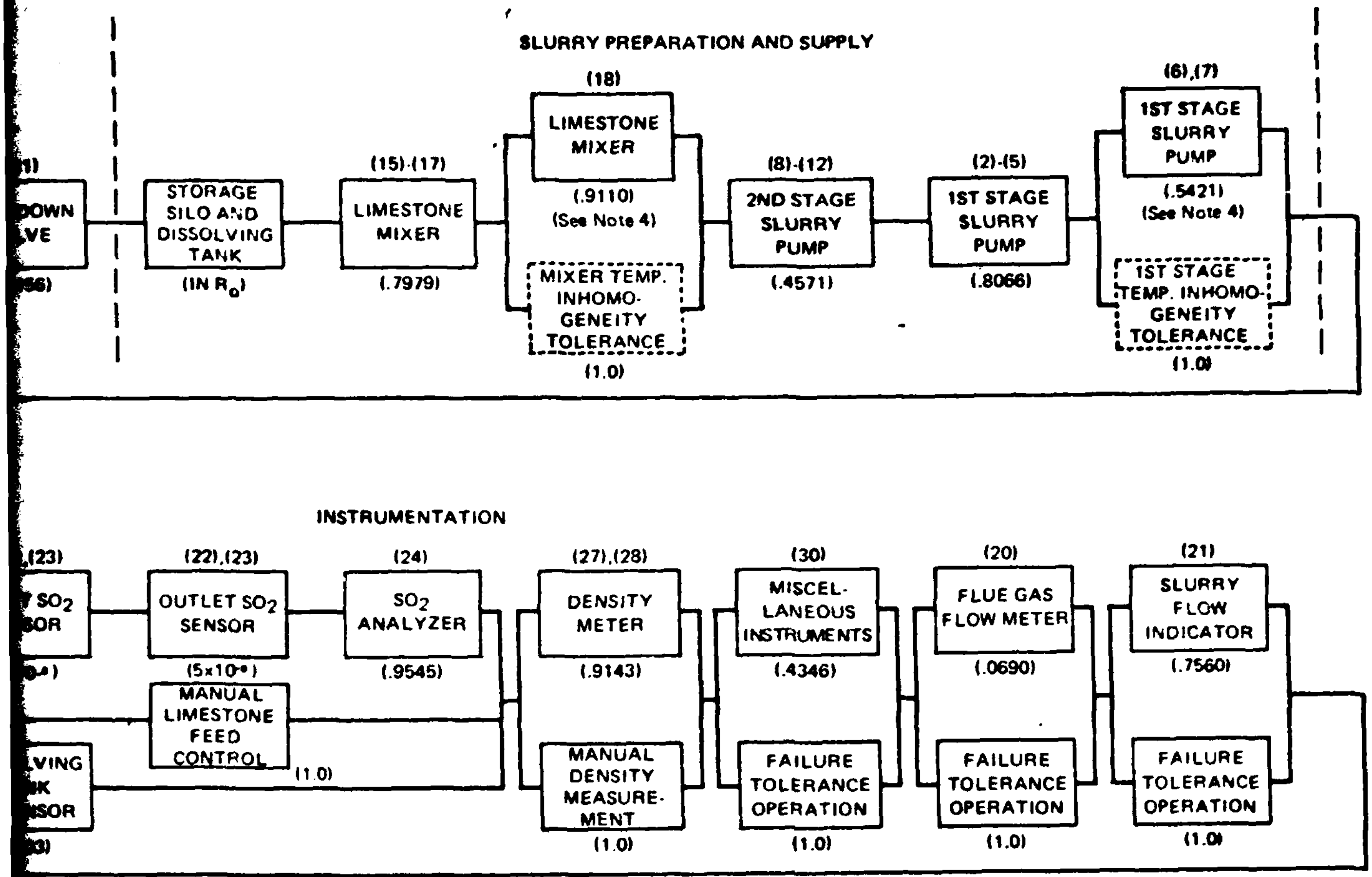


Figure 12-1
RELIABILITY BLOCK DIAGRAM – LIMESTONE SCRUBBER RICKENBACKER AFB, COLUMBUS, OHIO

/ 4 9

repair of a malfunction causing shutdown. The best measure for reliable operation from this point of view is the availability which is calculated later in this section.

12.8 MAINTAINABILITY

Maintainability as a mathematical measure was defined in Sections 2 and 10 as the probability that a work crew could correct a malfunction within a single 8-hour work period.

Repair times obtained from Rickenbacker AFB personnel or estimated by Bechtel are given in Table 12-1 for each failure mode. Using equations (10-7) to (10-9), N, the total frequency of failures, can be calculated to be 49.459 per month; m, the frequency of failures that can be repaired in an 8-hour period, is 49.115, and the maintainability M is the ratio m/N:

$$M = 0.993 \qquad (12\text{-}3)$$

Other parameters also provide information about the maintainability of the scrubber. The expected total repair hours per month, T_r, can be computed by summing up the products of the failure frequency and the expected repair time for each failure mode, according to equation (10-10). The result is

$$T_r = 70.6 \text{ hours per month} \qquad (12\text{-}4)$$

The mean time to repair (MTTR) is the ratio T_R/N. This is

$$\text{MTTR} = 1.43 \text{ hours per failure} \qquad (12\text{-}5)$$

12.9 AVAILABILITY

Availability was defined in Sections 2 and 10. It measures the fraction of time the FGD system performed as required during a period. It is the best measure of the ability of a scrubber to perform "reliably." It is calculated from the frequencies and the times to repair for critical failure modes.

Critical failure modes can be defined as failure modes of components that do not have backup components in parallel. These can be readily identified on the reliability block diagram (Figure 12-1). A failure in a critical mode will require a forced system shutdown, whereas noncritical failures will not. The expected total critical repair time, T_c, was defined in equation (10-12).

The availability, A, is derived from T_c according to equations (10-13) and (10-14). Values for T_c and A for the configuration at Rickenbacker AFB are as follows

$$\left.\begin{aligned} T_c &= 9.93 \text{ hours per month} \\ A &= 98.6 \text{ percent} \end{aligned}\right\} \quad \text{(Rickenbacker plant)} \qquad (12\text{-}6)$$

If spare slurry circulation pumps were available, the values for T_c and A would be

$$\left.\begin{aligned} T_c &= 5.29 \text{ hours per month} \\ A &= 99.3 \text{ percent} \end{aligned}\right\} \quad \text{(plant with spare pumps)} \qquad (12\text{-}7)$$

In deriving the availabilities above, failures of components with blocks in parallel on the reliability block diagram have been ignored. This is because the availability of at least one of a pair of blocks in parallel approaches 100 percent. This can be shown for the diaphragm pumps. A single sludge pump has an expected monthly repair time of 2.84 hours and hence an individual availability, A_i, from equation (10-13) of 99.6 percent. The reliability (and availability) of the pair given by equation (10-6) turns out to be 99.998 percent. In the same way, a pair of parallel slurry circulation pumps would have an availability of 99.999 percent.

12.10 COMMENTS ON R AND M CALCULATIONS

The reliability value of 0.23 for the R-C/Bahco scrubber at Rickenbacker AFB is actually quite good. The methods of Section 10 show that this reliability can also be written as exp (-1.45), which means that only 1.45 forced shutdowns would be expected per month. Note also that this expected number assumes that all failures occur at random with no scheduled shutdowns. Many of the failure modes contributing to the 1.45 are actually corrected in annual shutdowns for scheduled maintenance. Thus, the expected number of unscheduled shutdowns is actually lower than suggested above.

The relatively low number of expected shutdowns results in part from the assigned frequencies in various failure modes. Failures were considered only if they occurred between September 1977 and June 1979 (a 21-month period). This recording period was chosen, since prior operation was assumed to have been a "burn in" period in which defects showed up early and not in a random fashion. However, from the Rickenbacker data, it was possible to ascertain that certain components which failed only once in the 21-month recording period had not failed previously in the entire 39-month life of the plant. Thus, those failure modes were assigned a frequency of once in 39 months.

The 70.6 hours per month of expected maintenance activity would occupy only 44 percent of the work time of a single operator-maintenance man. Thus, the assignment of only a single operator to the scrubber seems reasonable. It should be noted that the 70.6 hours per month of expected repair activity does not include supply delays, inspection time, and other delays that can be classified as "administrative" delays.

The availability value calculated is an inherent availability depending only on the 9.93 critical mode hours among the 70.6 total expected maintenance hours. The resulting availability of 98.6 percent is quite good, and it would still look good even if an ample allowance for administrative delays were included. For instance, 16 days per year devoted to scheduled

shutdowns amounts to 32 hours per month. Suppose the scheduled shutdown plus unscheduled critical mode shutdowns amounted to 36 hours per month as an annual average. Then the actual overall annual average availability would be 95 percent. During the operating year June 1978 to June 1979 approximately 25 hours per month emergency shutdown hours were reported. If this is added to 32 hours per month for the annual scheduled shutdowns, the annual availability would have been 92 percent. If the annual shutdown hours are excluded, the availability with the reported forced shutdown hours would be 96.5 percent.

12.11 OPERATION AND MAINTENANCE FACTS

One full-time operator is dedicated to the scrubber. He works during the day shift, five days a week. At other times, the scrubber is monitored by boiler plant personnel. During unusually cold weather, an airman is assigned during each watch period to purge the level tank periodically to prevent freezeup.

The components requiring close tolerance manual control are:

- The lime/limestone feed control system (due to inadequate automatic control of the SO_2 measurement system)
- Blow down values
- Sludge flow control (to prevent thickener overflow when one of the sludge pumps is shut down for repair)

The components that may require quick operator action to avert malfunctions are:

- Booster fan and bypass control system (to avoid implosions)
- Second-stage slurry pump
- Process water booster pump

The educational background of operators should include training in electronics and instrumentation and a course in high school chemistry.

Preventive and scheduled maintenance includes:

- Lubrication (by operators)
- Cleaning of instruments and equipment (by operators)
- Unclogging of second-stage-level tank discharge line and pond lines (by operators)
- Pump diaphragm replacements (by operators)
- Scale removal (by shutdown labor crew)
- Pump liner replacements (by mechanics)

Some supply problems occur occasionally because of the procurement procedures at the Air Force Base, but for the most part, purchase requests are processed promptly when they are properly expedited. Some manufacturers have not been prompt in repairing equipment sent for service.

Maintenance problems during the "shakedown" period prior to September 1977 included:

- Cracks in the fan wheel rim due to resonant vibration (vibration reduced by bearing support and instrumentation changes)
- Errors in the fabrication of the thickener mechanism
- Failure of the water booster pump bearing
- Freezeup under $-23^{\circ}F$ and $-50^{\circ}F$ wind chill during the winter of 1976 to 1977 (corrected by supplementary heat tracing and insulation and substitution of manual for compressed air actuated blowdown valves)

Section 13

NIPSCO WELLMAN-LORD/ALLIED CHEMICAL SCRUBBER

13.1 INTRODUCTION

A visit was made to the FGD installation at the Northern Indiana Public Service Corporation (NIPSCO) Mitchell Station on July 12, 1979. The FGD system at NIPSCO is the first application of the sodium sulfite-bisulfite regenerable technology to coal-fired utility power generation in the United States. The installation uses the Wellman-Lord SO_2 recovery process developed and owned by Davy McKee Corporation, and a process for reducing SO_2 to elemental sulfur provided by Allied Chemical Corporation. The facility was jointly financed by NIPSCO and the U.S. Environmental Protection Agency (EPA) to demonstrate the Wellman-Lord/Allied Chemical technology. The facility was designed to operate for a short demonstration period only.

Information presented in this section has drawn upon data collected during the visit and information taken from References 17, 18, and 19.

13.2 GENERAL INFORMATION

The FGD system is retrofitted to NIPSCO's 115 megawatt pulverized coal-fired Unit No. 11 at Mitchell Station in Gary, Indiana. It is jointly owned by NIPSCO and EPA. It is operated by Allied Chemical Corporation under contract from NIPSCO. Davy Powergas, Inc. performed the design, procurement, and construction supervision for the plant, which was completed in August 1976.

The FGD system is designed to desulfurize 320,000 standard cubic feet per minute of entering flue gas. An electrostatic precipitator is upstream of the FGD system.

The Wellman-Lord process employs wet absorption of SO_2 from flue gas by reaction with sodium sulfite (Na_2SO_3) to form sodium bisulfite ($NaHSO_3$) and some sodium sulfate (Na_2SO_4). Desulfurized flue gas could be (but is not) reheated and released to the atmosphere. The absorber effluent liquor is filtered to remove solids and divided into two streams, a portion going to the regeneration area and the remainder going to purge treatment to reject the unreactive sodium sulfate. Evaporator/crystallizers are used to convert the dissolved $NaHSO_3$ to crystalline Na_2SO_3 and liberated SO_2. The regenerated Na_2SO_3 crystals are dissolved and returned to the absorbers. The regenerated SO_2 stream is converted to elemental sulfur by reduction with natural gas in an *Allied Chemical SO_2 reduction plant.*

The installation was made to demonstrate the technology for U.S. utility FGD application. NIPSCO's facility is the first combination of the proven Wellman-Lord process and the new Allied Chemical process.

The facility permits NIPSCO to meet SO_2 removal requirements when burning high sulfur coal. It offers the economic benefit of lower cost for short-term high sulfur coal contracts compared to long-term contracts for low sulfur coal. It also requires less real estate than sludge-forming FGD processes since ponding and landfill are eliminated.

The intended service life of the facility was three to five years as a demonstration plant. At the time of the visit, the plant had been in service for three years.

The Babcock and Wilcox boiler in Unit No. 11 is fired with washed Southern Illinois subbituminous coal from the Captain Mine containing 3.0 to 3.5 percent sulfur.

13.3 ECONOMICS

The capital cost of the facility was originally projected at $11,000,000 in 1974-1975 dollars. Strikes and construction delays drove the actual cost to $16,000,000. NIPSCO contributed $10,500,000 to the joint venture.

Operating costs in 1979 dollars run $325,000 per month excluding amortization and utilities. Operating, maintenance, and improvement costs during the period from September 16, 1977 to December 31, 1978 taken from Reference 18 were as follows:

• Operation and maintenance for offsite facilities (includes booster blower, flue gas ductwork and dampers, and utility systems)	$ 520,700
• Operation and maintenance within the FGD system battery limits, including storage and loading of by-products and unloading and storage of raw materials	$3,309,200
• Steam at $2 per 1,000 pounds	$ 895,500
• Demineralized water (September 1977 through February 1978 at $.03 per gallon, March through December 1978 at $0.0125 per gallon; abnormally high use because of design error)	$ 531,900
• Electric power at $0.024/kWh	$ 160,600
• Natural gas at $1.98/$10^6$ Btu	$ 121,900
• Credit for sulfur and sodium sulfate	$ (-97,000)
• Total operating, maintenance, and improvement costs after by-product credit	$5,442,800

13.4 EFFICIENCIES

The plant was designed to remove 90 percent of the SO_2 entering with the flue gas. Actual removal ranges between 89 and 92 percent. Soda ash utilization is 99^+ percent under design conditions.

Utilities consumed by the scrubber include the following:

- 7 megawatts of electricity (giving a power consumed to power plant output ratio of 6 percent)
- Steam consumption ranges between 50,000 pounds per hour in the summer to 66,000 pounds per hour in the winter.
- Natural gas for reduction of SO_2 is consumed at a rate of 110,000 cubic feet per day. The heating value is approximately 1050 Btu per standard cubic foot.

13.5 CONFIGURATION

The FGD system consists of a single scrubbing and regeneration train with gas processing capacity 12.5 percent in excess of design.

Installed spare components include some pumps. The SO_2 superheater has a spare in storage.

Critical parts kept in inventory include rotor blades for the forced draft fan and components for the SO_2 superheater and the sulfur condensors. Most items are not kept on hand because the Gary-Chicago area is a high inventory geographical area.

13.6 OPERATIONAL LIFE PROFILE

Conditions encountered during the life of the scrubber system which define its "operational life profile" include:

- Flue gas flows between 200,000 and 360,000 standard cubic feet per minute (The system can operate at the extreme conditions for periods no longer than 8 hours.)
- Temperatures between -20^{o}F and 100^{o}F
- Wind velocities up to 70 miles per hour
- Air containing dust from nearby steel and cement plants

The system is sensitive to particulates carried over with the flue gas. The Wellman-Lord prescrubber is designed to handle about 3 to 4 percent of the fly ash produced by the boiler. Consequently, the absorber could not operate if the electrostatic precipitator upstream of the FGD system were to fail. The precipitator is designed to remove 96 to 97 percent of the fly ash.

13.7 RELIABILITY

Table 13-1 is a failure mode and effects analysis (FMEA) for NIPSCO's FGD system during the period from September 16, 1977 to December 1978. During this period, the scrubber system was operated intermittently for 157 days (or 6 months). During the balance of the period, repairs were being made. Several failures which were corrected during that period were due to initial design or equipment flaws. These failures were considered "shakedown failures" and were not included in Table 13-1. The remaining failures were considered random and were included.

For each failure mode, Table 13-1 shows the component which failed, the cause, the effect on the system, and remarks about stress levels and requirements for shutdown. The table also shows the reported or estimated average outage time for each mode, its frequency of occurrence, and the mean time between failures (MTBF) computed from the frequency using Table 10-1.

Figure 13-1 is a simplified reliability block diagram for NIPSCO's FGD system. The diagram shows components that failed, as well as other components to present a complete reliability picture of the facility. From the reliability shown below each block, a total system reliability R can be computed to be

$$R = 2 \times 10^{-4} \qquad (13\text{-}1)$$

This corresponds to 8.5 forced outages expected per month.

R is the probability that the FGD system can operate continuously for one month without a forced shutdown. The use of a one-month failure-free criterion was an arbitrary choice made for this study, and it has little applicability in other contexts. The resulting probability R is more a measure of what the Navy calls "operability," or ease of operation, than a measure of reliable operation for meeting environmental standards continuously over a period of time. This is because the system can be restarted after repair of a malfunction causing shutdown. The best measure for reliable performance from this point of view is the availability, which was defined in Section 10.

The value of R from equation (13-1) is low because of the nature of NIPSCO's FGD system. Reasons for expecting such a result include:

- The NIPSCO facility was not designed to ensure low failure frequency because experienced chemical plant operators and maintenance personnel would be operating the plant
- NIPSCO's facility is a demonstration plant that was designed for a short service life on a limited budget. Design and equipment shortcuts were taken and a higher incidence of failure was likely to result
- The regenerable technology is the most complex of the systems considered in this study. Consequently it included more components that could fail
- In a commercial rather than a demonstration configuration, spare components would most likely be provided to guarantee the desired level of reliability

The following two modifications of the NIPSCO facility would have an interesting effect on system reliability:

- The gas supply system could be redesigned to perform without failure during a six month period — eliminating failures (1) to (4)
- Six-day storage tanks could be provided for absorber feed liquor and spent liquor — putting the tank storage in parallel to failures (5) to (17)

Failure Number	Component and Function in System	Failure Mode (Subcomponent Failing)	Failure Cause	Effect of Failure on Syst
1	Booster fan	Fan balancing, cleaning, reblading, bearing repairs, bearing oil leak	Fly ash, ice and water accumulation, corrosion, erosion	System becomes inoperativ
2	Booster fan turbine	Bearing repairs, governor repairs	Governor exposure to outdoor weather and dust	System becomes inoperativ
3	Flue gas duct	Leakage	Corrosion	Safety hazard created
4	Guillotine isolation damper	Damper frame and side channels	Mechanical damage to seals due to fly ash accumulation corrosion	System becomes inoperativ
5	Evaporation circulation pump turbine drive	Packing	Erosion	Extensive future damage o component if not repaired
6	Evaporation circulation pump turbine drive	Bearing	Wear	Extensive future damage o component if not repaired
7	Evaporation heat-exchanger	Tube leakage	NI	System eventually becomes inoperative
8	Evaporation heater	Tube leakage	NI	System becomes inoperati
9	Evaporator	Solution line gasket	NI	System becomes inoperati
10	Booster pump	Pump	NI	System becomes inoperati

Notation:
* = Bechtel estimate
NI = No information available
S = Stress level
A = Action taken

Table 13-1

FAILURE MODE AND EFFECTS ANALYSIS (FMEA) —
WELLMAN-LORD/ALLIED CHEMICAL PROCESS
NIPSCO, GARY, INDIANA
PERIOD: 9/16/77 — 12/31/78
157 Days (6 Months) of Scrubber Uptime

Failure Cause	Effect of Failure on System	Remarks	Average Outage Time, Days	Failure Frequency, Failures Period	Mean Time Between Failures (MTBF), Months
Fly ash, ice and water accumulation, corrosion, erosion	System becomes inoperative	S = High A = System shutdown for component repair and cleaning	67/9	9/6 mos	.62
Governor exposure to outdoor weather and dust	System becomes inoperative	S = High A = System shutdown for component repair	26/5	5/6 mos	1.06
Corrosion	Safety hazard created	S = High A = System shutdown for component repair	0.2	1/6 mos	3.58
Mechanical damage to seals due to fly ash accumulation corrosion	System becomes inoperative	S = High A = System shutdown for component repair	32/3	3/6 mos	1.63
Erosion	Extensive future damage of component if not repaired	S = Normal A = System shutdown for component repair	7	1/6 mos	3.58
Wear	Extensive future damage of component if not repaired	S = Normal A = System shutdown for component repair	5	1/6 mos	3.58
NI	System eventually becomes inoperative	S = NI A = System shutdown for component repair	6	1/6 mos	3.58
NI	System becomes inoperative	S = NI A = System shutdown for component repair	4.5	1/6 mos	3.58
NI	System becomes inoperative	S = NI A = System shutdown for component repair	4	1/6 mos	3.58
NI	System becomes inoperative	S = NI A = System shutdown for component repair	2	1/6 mos	3.58

Failure Number	Component and Function in System	Failure Mode (Subcomponent Failing)	Failure Cause	Effect of Failure on Sys
11	Instruments	SO_2 absorption solution regeneration, SO_2 reduction systems	NI	System becomes inoperati
12	SO_2 compressor	Gasket	Leakage	System becomes inoperati
13	SO_2 compressor	Turbine	NI	System becomes inoperati
14	SO_2 reduction reactor	Catalyst	Replacement	System becomes inoperati
15	Sulfur condenser	Tubes	Leakage	System becomes inoperati
16	Coalescer	Pluggage	NI	System becomes inoperati
17	Tail gas incinerator	NI	Malfunction	System becomes inoperati

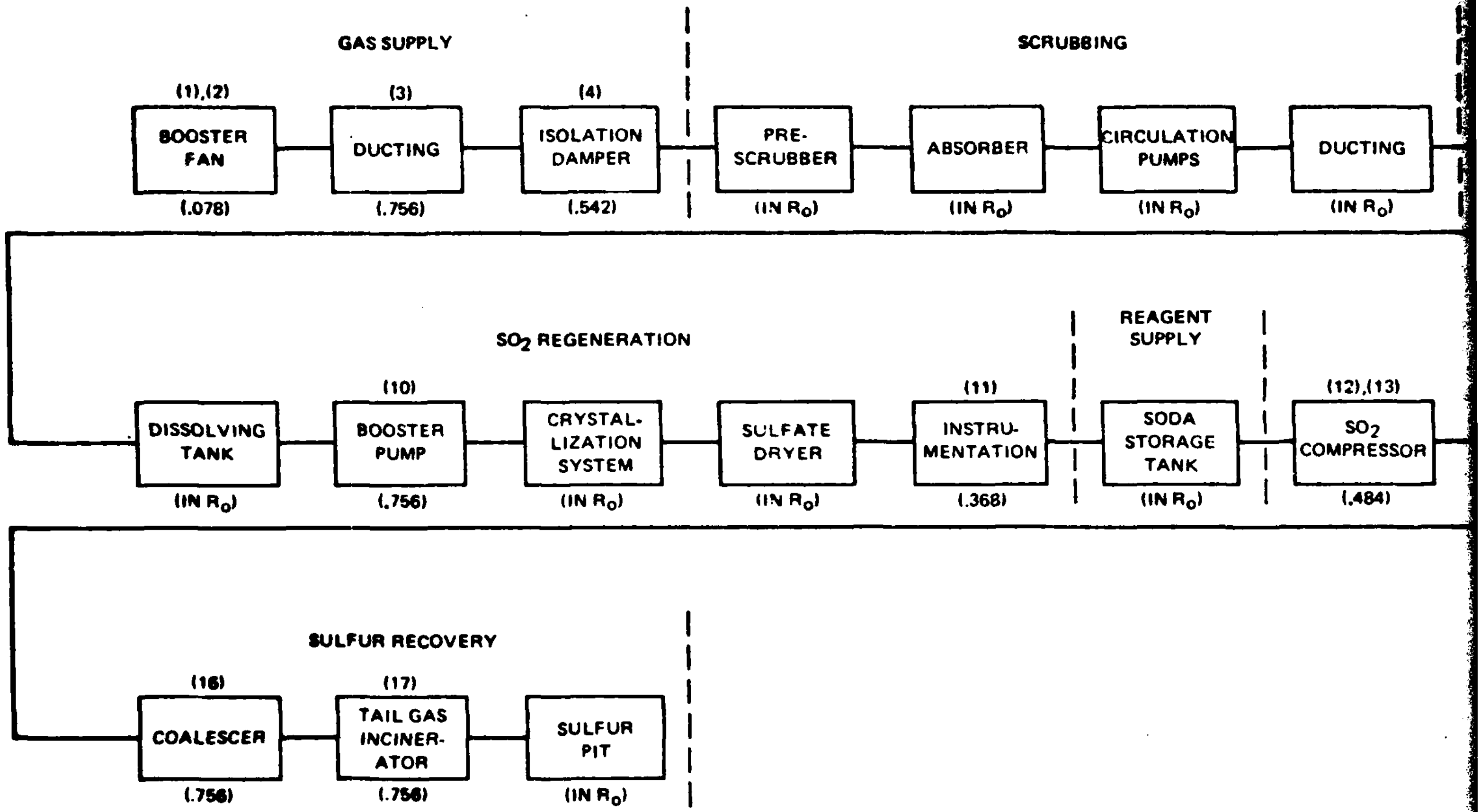
Notation:

* = Bechtel estimate
NI = No information available
S = Stress level
A = Action taken

Table 13-1 (Continued)

...re Cause	Effect of Failure on System	Remarks	Average Outage Time, Days	Failure Frequency, Failures Period	Mean Time Between Failures (MTBF), Months
	System becomes inoperative	S = NI A = System shutdown for component repair	3/6	6*/6 mos	1.00
...ge	System becomes inoperative	S = NI A = System shutdown for component repair	2/2	2/6 mos	2.24
	System becomes inoperative	S = NI A = System shutdown for component repair	0.1	1/6 mos	3.58
...acement	System becomes inoperative	S = NI A = System shutdown for component repair	5	1/6 mos	3.58
...age	System becomes inoperative	S = NI A = System shutdown for component repair	2/3	3/6 mos	0.61
	System becomes inoperative	S = NI A = System shutdown for component repair	5	1/6 mos	3.58
...unction	System becomes inoperative	S = NI A = NI	2	1/6 mos	3.58

164



R = Combined system reliability (probability of operating for one month without shutdown) = 0.0002.

Notes:

1. Numbers in parentheses on top of blocks denote failure items from FMEA (Table 13-1).
2. Number in parentheses below each block is the reliability of the block.
3. The expression "(In R_o)" indicates that the reliability for that block is part of a series of blocks with combined reliability R_o. The value of R_o is 0.891, corresponding to zero failures in six months.

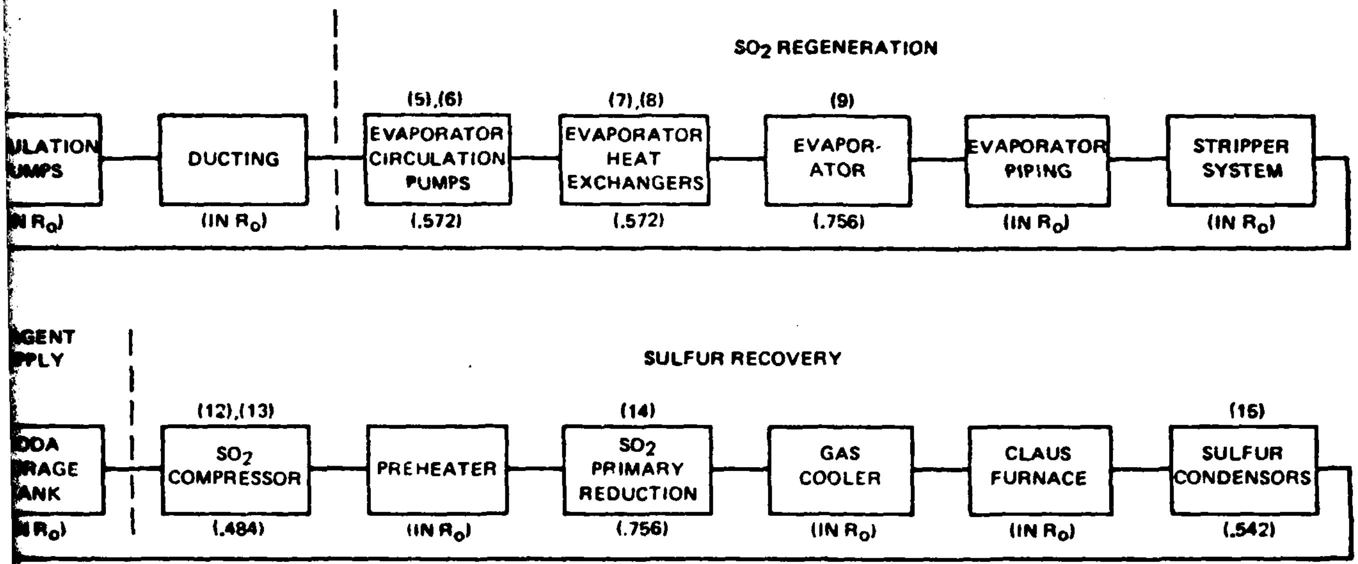


Figure 13-1
RELIABILITY BLOCK DIAGRAM – WELLMAN-LOSD/ALLIED CHEMICAL PROCESS NIPSCO, GARY, INDIANA

The first change above appears reasonable, since it is likely that the NIPSCO gas supply system is marginally designed, and the gas supply system, which is not peculiar to any technology, should not be allowed to adversely affect the reliability rating of a particular technology.

The addition of six-day storage tanks would decouple all liquor processing components (the so-called "chemical plant" part of the installation) from the continuous operation of the absorber, since any failure in Table 13-1 could be repaired within six days.

The resulting reliability would then be $R_o = 0.891$, which is extremely high.

It is also quite interesting that Table 13-1 includes no failures at all for the absorber or prescrubber, which are hence quite reliable.

13.8 MAINTAINABILITY AND AVAILABILITY

The outage times in Table 13-1 are measured in days rather than hours. The outage times clearly include time for major administrative delays; from the available published information it was not possible to determine or estimate inherent repair times which assume a work crew was available with necessary parts and tools to correct each failure as soon as it occurred. Consequently, it is impossible to calculate meaningful values for maintainability or availability as defined in this study. The availability reported to EPA for the 16-month period was approximately 30 percent. EPA considers this abnormally low,* caused primarily by design and equipment shortcuts associated with a low budget demonstration plant, rather than a true indication of the performance of the Wellman-Lord/Allied Chemical technology.

---

*Telephone comments to Bechtel by C. Chatlynne of EPA on June 29, 1979.

13.9 OPERATIONS AND MAINTENANCE FACTS

Operating manpower includes three operators per shift for four shifts, plus three relief operators, a total of 15 operators. Two laboratory technicians work during the day shift seven days a week.

The lowest level operating job (outside operator) requires one month of training. Twenty percent of this training covers basic safety in chemical operations. Other operating jobs require prior experience. Prior training in basic chemistry is not needed.

Quick operator action is required to handle:

- Failure of electrostatic precipitators or fan
- Failure of evaporator pump
- High H_2S concentration indicated by H_2S detectors

Preventive maintenance is performed on a daily basis. In-line pH meters are compared daily with laboratory pH meters. Electrodes of pH meters are cleaned once every two months.

Normal maintenance is performed by a single maintenance man who spends approximately 24 hours per week on preventive maintenance and approximately 16 hours per week on special maintenance problems.

Scheduled maintenance is performed during the annual boiler shutdown. Every third year this shutdown lasts six weeks; other years the shutdown lasts three weeks. During the shutdown, equipment is cleaned, worn parts are replaced, and instruments are cleaned, adjusted, and repaired. The crew for this annual scheduled maintenance is a 9- to 11-man force of mechanics, electricians, and instrument mechanics. In addition, crane

operators, laborers and others on special assignments (such as big insulation jobs) are provided as needed.

No significant supply problems are encountered. The Chicago area is a high-inventory, good supply area. Allied Chemical performs purchasing and NIPSCO pays the expenses. NIPSCO will handle requests for bids for items exceeding $50,000. No notable delays seemed to be associated with repair crew assignment or purchasing procedures.

"Shakedown" problems corrected since September 1977 included:

- Repair of the rubber liner in the absorber. The liner had not been correctly bonded during installation
- Problems with badly designed booster fan system
  - Vibration due to imbalance
  - Ice and ash coating and corrosion of blades
  - Failure of bearings
  - Failure of turbine drive governor
  - Oil freezeup
  - Nonenclosed turbine drive
  - Lube seal break
  - Turbine bearing failure
  - Absence of soot blowers
- Guillotine damper problems including jamming open, push rod breakage, the need for inordinate bottom channel cleaning, and the lack of manually controlled dampers
- Failure of the evaporator circulation pump to operate when steam supply was down. This was corrected by switching from steam turbine drive to electric drive

- Failure of the boiler demineralizer to adequately serve both the FGD system and the boiler. A supplementary system was installed

- Steam pressure reduction valve problems between May and July 1978

Section 14

GENERAL MOTORS ST. LOUIS SODIUM HYDROXIDE SCRUBBER

14.1 INTRODUCTION

A visit was made to the scrubber installation at the St. Louis manufacturing plant of General Motors Assembly Division (GMAD) on July 23, 1979.

General Motors decided in the middle 1960s to develop their own processes for removing SO_2 from flue gases produced by burning high sulfur coal. In the Fall of 1972, they completed the sodium hydroxide scrubbing installation at their St. Louis plant. The sodium hydroxide system was feasible in St. Louis because the water authorities there have allowed the effluent to be discharged into the city sewer system after it has been aerated.

The information presented in this section has drawn upon data collected during the visit, and information taken from References 11, 20, and 21.

14.2 GENERAL INFORMATION

The facility is owned by General Motors Corporation and operated by GMAD. It is located within the city limits of the city of St. Louis. The equipment was designed by A. D. Little, Inc.

The boiler system at the St. Louis plant includes an operating spreader stoker and two pulverized coal boilers. Two of the boilers are connected to the scrubber system.

The system has two parallel scrubbing trains, one with a capacity to process 36,000 standard cubic feet per minute of entering flue gas, and a

second with a capacity to handle 57,000. The combined capacity corresponds approximately to 31 megawatts electric, or 310 x 10^6 Btu per hour of coal heat input.

The sodium hydroxide scrubbing is carried out in a three-stage tray tower. The raw material for the process is soda ash (sodium carbonate). The liquor from the scrubber is aerated to convert sodium sulfite to sodium sulfate, the liquor is then discharged to the sewer.

The installation was made to allow compliance with state environmental standards. The scrubbers permitted use of high sulfur coal compatible with the electrostatic precipitators previously installed. The alternative, use of low sulfur coal, would not have resulted in as good precipitator performance. The 3.5 percent sulfur Southern Illinois subbituminous coal used is available within trucking distance and is more economical than low sulfur coal.

To comply with local regulations, it is only necessary to operate the scrubber from October to March each year.

The facility was privately financed. The owners have not presented any calculations of payback through fuel savings. Information on the design life was not available. The facility service life at the time of the visit was approximately six years and nine months.

14.3 ECONOMICS

The capital cost of the facility in 1973 dollars was $773,000, according to Reference 11.

Operating costs in 1976 were $172,000. This included maintenance materials, labor, and electricity.

14.4 EFFICIENCIES

General Motors' St. Louis installation has demonstrated 90+ percent SO_2 removal efficiency. Reagent utilization is virtually 100 percent. Approximately 170 pounds of 50 percent NaOH are consumed per ton of coal burned. The boiler plant consumes approximately 40,000 tons of coal per year.

General Motors did not provide data on the power, steam, or fuel demands of their St. Louis scrubbing system.

14.5 CONFIGURATION

The FGD system has two parallel absorber trains and one waste liquor handling and chemical supply train. Each SO_2 removal train is sized to accommodate the output of a particular boiler, but an inlet crossover duct is provided, so that under a certain load regime, one train acts as a standby spare for the other.

The boiler plant serves the space heating demands of the plant. At peak load (in very cold weather) there is no excess scrubber capacity. Under these conditions, when the flue gas from the two controlled boilers is scrubbed, the overall heating plant emissions satisfy the St. Louis limit of 2.3 pounds of SO_2 per million Btu of coal heat input.

No components in the system are spared.

No major parts are kept in a critical parts inventory since St. Louis is a high inventory center for industrial components.

14.6 OPERATIONAL LIFE PROFILE

Conditions encountered during the scrubber life which define its "operational life profile" include:

- Ambient temperatures between $-15^{o}F$ and $80^{o}F$
- Coal sulfur levels between 2.9 and 3.5 percent
- Load turndown ratios of 3 to 1 for each train

During the heating season, the boiler plant operates continuously with varying load. In usual operation, the large scrubber train (Number Two) is in continuous operation throughout the season, and the small scrubber train (Number One) is used intermittently depending on the load. During the summer season, both scrubbers are shut down.

The system is sensitive to particulate loading. Gas to one scrubber first passes through a mechanical collector, which removes 90 percent of the particulates. Gas to the other scrubber first passes through electrostatic precipitators which have removal efficiency of 98 to 99 percent.

General Motors claims that the two-scrubber FGD installation has a 90+ percent on-stream utilization, so downtime is less than 10 percent of the operating season.

The scrubbers do not operate from April to September.

14.7 RELIABILITY

The reliability of General Motors' St. Louis scrubber was evaluated based on failures from the period from September 1977 to March 1979. Since the system was down during the six hot months of 1978, the evaluation period included only twelve operating months.

A failure mode and effects analysis (FMEA) of ten failure modes is presented as Table 14-1. For each mode, it shows the component failing, the cause, the effects on the system, and remarks on stress levels and requirements for the system shutdown. The table also shows the reported or estimated time required to correct each malfunction, its frequency of

Component and Function in System	Failure Mode (Subcomponent Failing)	Cause	Effect of Failure On System	Remarks
Booster fan #1 & #2 FGD systems	1) Suction damper operator motor	Undersized	System function more inconvenient	S = NI A = Reestablished
	2) Bearing	Wear	System becomes inoperable	S = NI A = Replace bearing Sy shutdown required,
	3) Rotor balance	NI	System becomes inoperable	S = Normal operation A = Rebalance fan
Flue gas flow meter #1 & #2 FGD systems	4) Annubar type flow element	Plugging with fly ash	System function more inconvenient	S = Normal A = Flow elements clean blow back
Caustic supply pumps #1 & #2 FGD systems	5) Diaphragm	Wear	System function more inconvenient	S = Normal A = Diaphragm replaced down not required b porary surge tolera the liquor system
Caustic recirculation pumps #1 &#2 FGD systems	6) 316L SS pump casing	Erosion	NI	S = High A = Casing reconstructe surface. Work perf summer shutdown
pH meter	7) Glass electrode	Coating by solids	System function more inconvenient	S = Normal A = Electrode removed, ted. System shutdo
Ducting	8) Common treated fluegas	Corrosion	NI	S = NI A = Replaced 304SS duct glass reinforced pl month annual shutdo
	9) #2 scrubber inlet	Corrosion	NI	S = NI A = Replaced duct durin
	10) #2 scrubber inlet	Cracking	NI	S = High A = Repaired cracks dur shutdown

Notation: * = Bechtel estimate
NI = Detailed information not provided
NA = Not applicable. Work staggered during 6-month annual shutdown to meet manpower availability

S = Stress Level
A = Action Taken

Table 14-1

FAILURE MODE AND EFFECTS ANALYSIS (FMEA) —
SODIUM HYDROXIDE SCRUBBING SYSTEM,
GENERAL MOTORS CORP., ST. LOUIS, MO.
PERIOD: 9/79 — 3/79
Plant in Operation Since 1973

f Failure stem	Remarks	Total Outage Hours	Failure Frequency Failure Period	Mean Time Between Failures (MTBF), Months
nction nvenient	S = NI A = Reestablished	1 ea	1/2 mos, ea	1.2
comes e	S = NI A = Replace bearing System shutdown required.	12* ea	1/yr, ea	3.6
comes e	S = Normal operation A = Rebalance fan	8* ea	1/ yr, ea	3.6
nction nvenient	S = Normal A = Flow elements cleaned by air blow back	1 ea	1/3 wks, ea	.45
nction nvenient	S = Normal A = Diaphragm replaced System shutdown not required because of temporary surge tolerance capacity of the liquor system	1 ea	1/3 yrs, ea	10.7
	S = High A = Casing reconstructed with hardened surface. Work performed during summer shutdown	NA	1/6 yrs, ea	21.4
nction nvenient	S = Normal A = Electrode removed, cleaned, calibrated. System shutdown not required.	1	1/2 wks	.3
	S = NI A = Replaced 304SS ducting with fiberglass reinforced plastic during 6-month annual shutdown	80*	1/6 yrs	21.4
	S = NI A = Replaced duct during annual shutdown	40*	1/6 yrs	21.4
	S = High A = Repaired cracks during annual shutdown	8*	2/6 yrs	21.4

evel
aken

177

occurrence, and the mean time between failures (MTBF) computed from the frequency using Table 10-1.

Figure 14-1 is a simplified reliability block diagram for General Motors' St. Louis scrubber. The diagram shows which components failed, as well as other components, to present a reliability picture of the complete facility. From the reliability below each block, an overall system reliability can be calculated. For this scrubber system, the overall reliability depends on the load regime. Table 14-2 shows the reliability in the various load regimes. Note that when one SO_2 removal train is a genuine idle spare for the other, the system reliability is extremely high.

The reliability calculated for components and the overall system is the probability that the system will be able to operate continuously for a full month without requiring a shutdown. As stated in Section 10, the "reliability" defined in this way is more a measure of what the Navy calls "operability" or ease of operation, than a measure of reliable operation for meeting environmental standards continuously over a period of time. This is because the system can be restarted after repair of a malfunction causing shutdown. The best measure for "reliable" operation from this point of view is the availability, which is calculated later in this section.

14.8 MAINTAINABILITY

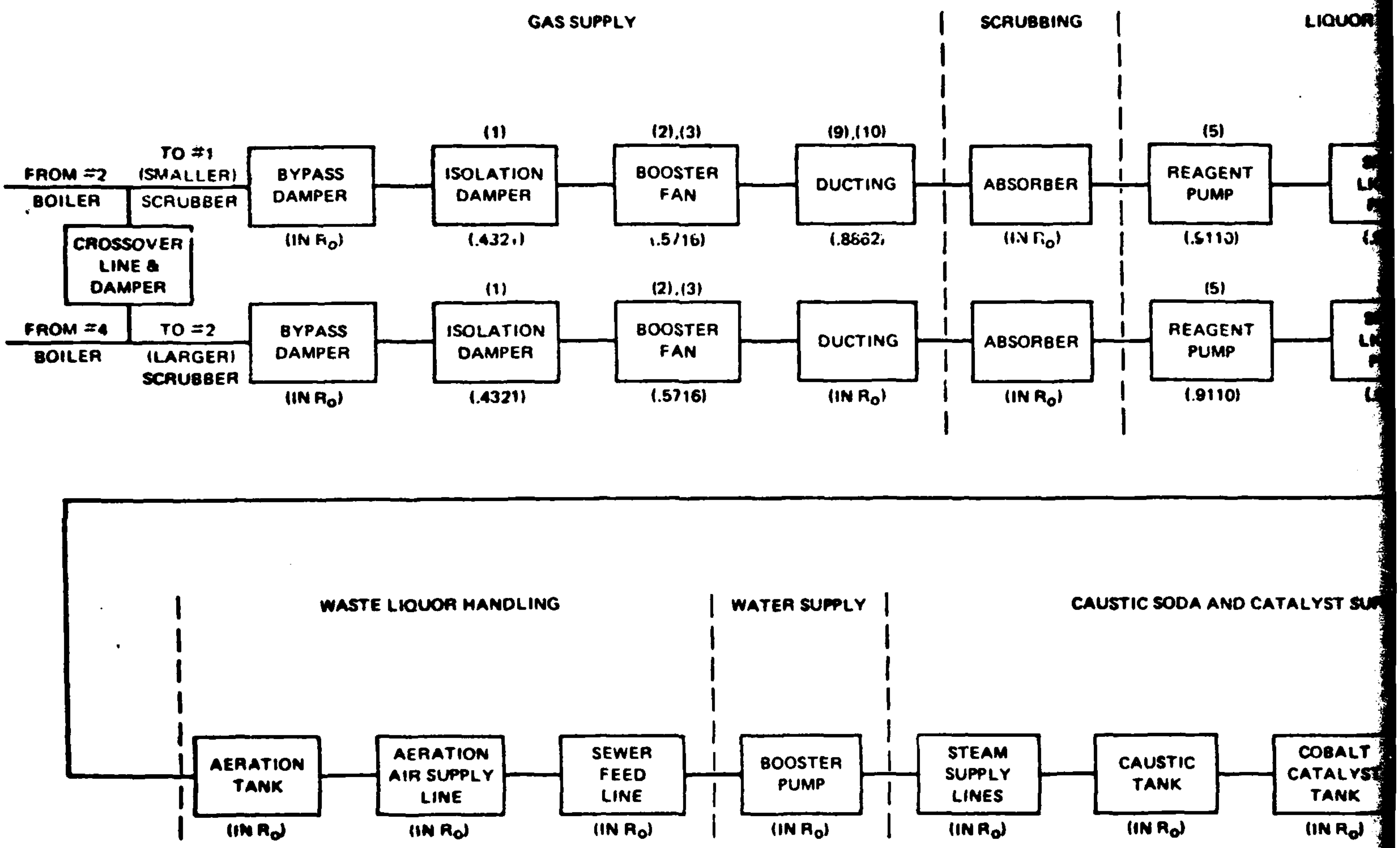
Maintainability as a mathematical measure was defined in Sections 2 and 10 as the probability that a work crew could correct a malfunction within a single 8-hour work period.

Repair times are given in Table 14-1 for each failure mode. By equations (10-7) to (10-9), N, the total frequency of failures, is 16.08 per month;

Table 14-2

RELIABILITY AND AVAILABILITY AS A FUNCTION OF LOAD REGIME

Load Regime	Load Range 10^3 SCFM	Operating Configuration	Reliability One Month	Reliability One Week	Avail-ability
1	0-12	Neither scrubber can operate; load is lower than minimum capacity of either.			
2	12-19	The small scrubber can operate; the load is below the minimum capacity of the larger.	.172	.644	.982
3	19-36	Either scrubber alone can handle the full load; the other serves as a parallel spare.	.901	.974	.995
4	36-57	The larger scrubber can handle the full load alone; the load exceeds the capacity of the small scrubber.	.194	.663	.983
5	57-93	Both scrubbers must operate simultaneously; neither can handle the full load alone.	.037	.438	.971



The overall plant reliability depends upon the load regime, and is given in Table 14-2.

Notes.

1. Numbers in parentheses on top of blocks denote failure items from FMEA (Table 14-1).
2. Number in parentheses below each block is the reliability for that block.
3. The expression "(In R_o)" indicates that the reliability of that block is part of a series of blocks with combined reliability R_o. The value of R_o is 0.9439, corresponding to zero failures in 12 months of scrubber operation.

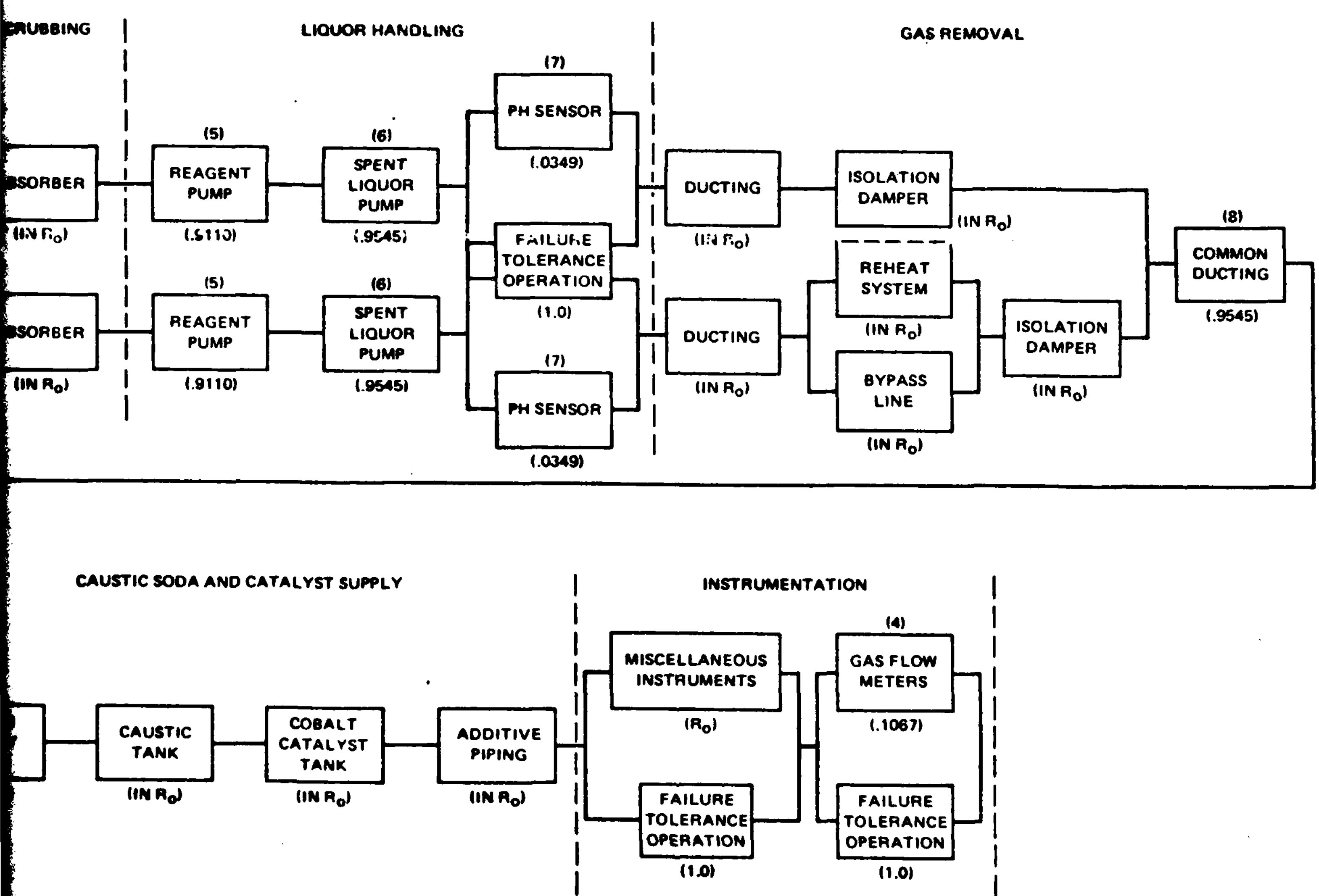


Figure 14-1
RELIABILITY BLOCK DIAGRAM–
SODIUM HYDROXIDE SCRUBBING SYSTEM
GENERAL MOTORS CORP., ST. LOUIS, MO.

m, the frequency of failures that can be repaired in an 8-hour work period; 15.329; the maintainability M is the ratio m/N:

$$M = 0.9594 \qquad (14\text{-}1)$$

Other parameters provide information about the maintainability of the scrubber. The expected total repair hours per month can be computed by summing up the products of the failure frequency and the expected repair time for each failure mode, according to equation (10-10). The result is:

$$T_r = 32.63 \text{ hours per month} \qquad (14\text{-}2)$$

The mean time to repair (MTTR) is the ratio T_r/N. This is

$$\text{MTTR} = 2.03 \text{ hours per failure} \qquad (14\text{-}3)$$

14.9 AVAILABILITY

Availability was defined in Sections 2 and 10. It measures the fraction of time the FGD system performed as required during a period. It is the best measure of the ability of a scrubber to perform "reliably." The availability is calculated from the frequencies and times to repair for critical failure modes.

Critical failure modes are failure modes of components that do not have backup components in parallel. These are readily identified from the reliability block diagram Figure 14-1. A failure in a critical mode will require a forced system shutdown, whereas noncritical failures will not. The expected total critical repair time, T_c, was defined in equation (10-12). The availability, A, is derived from T_c according to equations (10-13) and (10-14). Note that in one load regime in Table 14-2, each entire SO_2 removal train is an idle spare for the other, and consequently no failure modes in the two trains are critical. And in contrast, at peak load, both scrubbers must operate to handle the complete load, and in every failure mode, either train is critical. On the other hand, there are two load regimes which would require one of the two SO_2 removal

trains to operate but not the other. Hence failures in the idle train would not be critical.

Table 14-2 provides availabilities for the General Motors St. Louis scrubber in the various load regimes.

14.10 COMMENTS ON R AND M CALCULATIONS

The reliability of General Motors' St. Louis scrubber system is high, especially if it is noted that a cold spell requiring both SO_2 removal trains would seldom last longer than a week. In this case, probabilities should be computed on a basis of one week without failure rather than one month. The reliabilities calculated in this way are also shown in Table 14-2. It is seen that the peak load probability for operation for one week without failure is quite good, and the probabilities for the other regimes are correspondingly higher. For continuous operation of the largest scrubber alone (normal operation), the one-month reliability corresponds to only 1.64 critical failure per month, which is not excessive.

Even though failures were analyzed only during a recent 18-month period, it was known that certain failures that occurred only once during the observation period had in fact not occurred before in the entire 60-month life of the plant (40 operating months). The reliabilities associated with those failure modes were consequently substantially higher than if the recurrence was assumed to be once every 12 operating months.

The maintainability and repair hours per month are both characteristic of a low-maintenance system.

The availabilities from Table 14-2 are high. These are inherent availabilities which do not include supply or administrative delays. If these were included, the availabilities would be lower, but probably

consistent with General Motors' reported 90+ percent on-stream utilization.

14.11 OPERATION AND MAINTENANCE FACTS

The scrubber operation is integrated with boiler operation at General Motors' St. Louis plant, and no separate personnel are assigned especially to the scrubber. The boiler fireman is the scrubber operator. Training scrubber operators takes three to four weeks.

Routine control room operation and outdoor maintenance activity associated with the scrubber averages 1.5 to 2.0 hours per shift. Instrument cleaning and adjustment takes less than twenty hours per week.

Close tolerance manual control is required for regulating NaOH feed rate to match flue gas flows.

Quick operator action is required in failures of the scrubber booster fan or the main induced draft fan for the boiler.

Preventive and scheduled maintenance activities include:

- Lubrication
- Cleaning (usually done during the off-season)
- Unclogging (usually done during the off-season)

Scheduled maintenance during the off-season could be done in two to three weeks. The work is staggered to match availability of manpower.

During initial shakedown, the 304 stainless steel outlet ducts corroded through rather frequently, and were replaced by ducts of fiberglass-reinforced plastic.

Section 15

FIRESTONE FMC DOUBLE ALKALI SCRUBBER

15.1 INTRODUCTION

A visit was made to the scrubber installation at Firestone Corporation's Pottstown, Pennsylvania plant on July 27, 1979.

Firestone installed the scrubber so that it could burn a more economical fuel than compliance fuel oil. Installation was completed in January, 1975. Early use was with high sulfur fuel oil. Firing with coal began in October 1976.

The technology used is a concentrated double alkali process developed by FMC Corporation's Environmental Equipment Division. Firestone's installation is a pilot plant for demonstrating this technology for industrial boilers.

Information presented in this section has drawn upon data collected during the visit, and information taken from References 11, 20 and 21.

15.2 GENERAL INFORMATION

The facility is owned by Firestone Tire and Rubber Company. It is located in Pottstown, a rural community in southeastern Pennsylvania. The scrubber facility was manufactured by FMC and other contractors. It is jointly operated by Firestone and FMC.

The scrubber has the capacity to process 14,000 actual cubic feet per minute of flue gas entering at 350°F and 15 to 20 inches of water gauge pressure. This capacity corresponds to approximately 3 megawatts electric or [illegible] million Btu per hour of coal feed. This is approximately one-third of [illegible] total output of one 120,000 pounds per hour boiler at the plant.

The FMC Double Alkali process carries out SO_2 removal in a high efficiency, single-stage contactor referred to as a Venturi stage. In this contactor sodium sulfite scrubbing liquor is sprayed through nozzles onto a wedge-shaped adjustable insert in the Venturi throat. This creates a sheet of liquor falling from each side of the wedge. Flue gas passing at high velocity atomizes the sheet of liquor. The atomized droplets absorb SO_2. The gas and liquor are then separated in a mist separator. The liquor containing SO_2 is pumped to a reactor tank into which a lime slurry is added. Calcium sulfite precipitates, and the liquor drawn off is ready for reuse in the Venturi.

The facility is designed to demonstrate a 90 percent SO_2 removal efficiency from flue gas generated by burning Pennsylvania coal containing approximately 2.5 percent sulfur. The emission regulation for the plant is 1.2 pounds of SO_2 per million Btu of coal heat input.

The process forms 180 pounds per hour of filter cake containing 55 percent solids. This is hauled to an on-site unlined pit without addition of lime for fixing.

The boiler at the facility can fire pulverized coal, residual fuel oil, or a coal-oil mixture.

The facility was financed privately. The owners have not presented any calculation of payback through fuel cost savings. Since the scrubber is a pilot-demonstration plant, it was not designed for a specific service life.

15.3 ECONOMICS

The capital cost of the facility was $163,000 in 1974 dollars (Reference 11). This includes equipment and engineering and startup, but does not include labor and materials for electrical system, piping, foundations, or structural erection.

According to Reference 11, the operating costs in 1977 were $ 60,000. This includes chemicals, labor, electricity, disposal, materials, and lab work for 1977.

15.4 EFFICIENCIES

The system reportedly achieves 90 percent SO_2 removal. Lime utilization is 100 percent. Between three and five percent of the SO_2 removed is in the form of sulfate.

The facility does not use steam for reheat. A small amount of steam is used in the Venturi soot blower.

Information on power consumption was not available.

15.5 CONFIGURATION

The facility consists of a single process train, with no installed spare components.

Critical parts kept on hand include filter cloths and diaphragms, sleeves and linings for soda pumps.

15.6 OPERATIONAL LIFE PROFILE

Conditions encountered during the life of the scrubber which define its "operational life profile" include:

- Ambient temperatures between $-15^{\circ}F$ and $100^{\circ}F$
- Coal sulfur levels between 1.7 and 2.7 percent
- Flue gas flows between 6,500 and 14,000 actual cubic feet per minute (The scrubber is designed for a turndown ratio of 4 to 1)

The boiler and scrubber operate continuously without intermittent shutdown.

A mechanical separator upstream of the scrubber is designed to remove 80 percent of the particulates in the flue gas, but it actually removes 60 percent. The system is sensitive to the residual particulates.

The system is shut down for four weeks once a year for boiler maintenance.

15.7 RELIABILITY, OPERATIONS AND MAINTENANCE

No reliability, maintainability, or operability analysis is published here on the FMC scrubber at Firestone's plant.

The FMC scrubber at Firestone's Pottstown plant has an availability that is acceptable by chemical industry standards, although the failure frequency appears to be higher than for the scrubbers described in Sections 11, 12, and 13, possibly due to flyash and intermittent operation of the boiler.

The Firestone installation is a pilot plant, with ongoing equipment improvements being introduced. The installation is considered to be still in the "shakedown" phase. Thus, the failure frequency methodology described in Section 10 is less applicable.

FMC advises that their scrubber at Firestone's plant was not designed for the low failure frequency desired by the Navy. The technology does not represent that which they would offer for a Navy base.

Section 16

LIST OF U.S. FGD INSTALLATIONS FOR INDUSTRIAL COAL-FIRED BOILERS

Table 16-1 is a list of 16 operating flue gas desulfurization installations for coal-fired industrial boilers. The table was prepared from data in Reference 11.

Owner	Location	Vendor	Capacity SCFM	Startup Mo/Yr	Service Yrs	Reliability %, 1978 Qrs 1/2 3/4	Cost 10^3/Y Capital	Op
CAUSTIC WASTE STREAM								
Canton Textiles	Canton, GA	FMC Env. Equip.	25,000	6/74	5-3/4	100/100 (1)/99	138(d)	
CITRATE PROCESS								
St. Joe Zinc Co.	Monaca, PA	Bureau of Mines	142,000	4/79	1/2	(2)	12,000(b)	
DOUBLE ALKALI — CONCENTRATED								
Caterpillar Tractor Co.	Mapleton, IL	FMC Env. Equip.	131,000	3/79	1/2	(2)	—	
Caterpillar Tractor Co.	Mossville, IL	FMC Env. Equip.	140,000	10/75	4	(3)	—	
Firestone Tire & Rubber	Pottstown, PA	FMC Env. Equip.	8,070	1/75	4-3/4	(3)/90 100/93	163(d)	
DOUBLE ALKALI — DILUTED								
Caterpillar Tractor Co.	Joliet, IL	Zurn Industries	67,000	9/74	5	(3)	—	
Caterpillar Tractor Co.	Morton, IL	Zurn Industries	38,000	1/78	1-3/4	(3)/100 (3)/(3)	—	
General Motors Corp.	Parma, OH	GM Environmental	128,400	3/74	5-1/2	1.2/78 100/24	3,000(g)	
DRY LIME SCRUBBING								
Strathmore Paper Co.	Woronoco, MA	Mikropul Corp.	22,000	8/79	—	(2)	—	
LIME SCRUBBING								
Pfizer, Inc.	East St. Louis, IL	In-House Design	40,000	9/78	1	(2)/(2) (2)/96	1,800(a)	
LIMESTONE SCRUBBING								
Rickenbacker AFB	Columbus, OH	Research-Cottrell/Bahco	55,000	3/76	3-1/2	81/100 99.5/98.4	2,200(c)	
SODIUM CARBONATE SCRUBBING								
Texasgulf	Granger, WY	Swemco, Inc.	140,000	9/76	3	(3)/(3) (3)/100	250(h)	
SODIUM HYDROXIDE SCRUBBING								
General Motors Corp.	St. Louis, MO	A.D. Little	64,000	-/72	7-1/2	(3)	773(e)	
General Motors Corp.	Dayton, OH	Entoleter, Inc.	36,000	9/74	5	(3)	668(d)	
General Motors Corp.	Tonowanda, NY	FMC Env. Equip.	92,000	6/75	4-1/4	(3)	2,200(d)	
General Motors Corp.	Pontiac, MI	GM Environmental	107,300	4/76	3-1/2	(3)	600(f)	

Notes: (1) - FGD system shutdown during gas fired operation
(2) - Not applicable
(3) - Not available

(a) - 1978 Dollars
(b) - 1977 Dollars
(c) - 1975 Dollars
(d) - 1974 Dollars

(e) - 1973 Dollar
(f) - 1972 Dollar
(g) - Year not in
(h) - Information

Table 16-1

INDUSTRIAL SIZE COAL-FIRED FLUE GAS DESULFURIZATION INSTALLATIONS IN THE UNITED STATES

Startup Mo/Yr	Service Yrs	Reliability %, 1978 Qrs 1/2 3/4	Cost 10^3/Year		Coal Sulfur %		SO_2 Removal, %		No. Boilers Controlled	No. FGD Systems
			Capital	Operating	Design	Actual	Design	Actual		
6/74	5-3/4	100/100 (1)/99	138(d)	34	0.8	—	—	—	1	1
4/79	1/2	(2)	12,000(b)	—	2.5-4.5	—	—	—	1	1
3/79	1/2	(2)	—	—	3.2	—	—	—	3	3
10/75	4	(3)	—	—	3.2	—	—	—	4	4
1/75	4-3/4	(3)/90 100/93	163(d)	60	2.5-3	1.7-3.7	90+	90+	1	1
9/74	5	(3)	—	—	3.2	—	—	—	2	2
1/78	1-3/4	(3)/100 (3)/(3)	—	—	3.2	—	—	—	2	2
3/74	5-1/2	1.2/78 100/24	3,000(g)	644	2.5	2.5-3.5	90	95	4	1
8/79	—	(2)	—	—	0.75-3	—	—	—	1	1
9/78	1	(2)/(2) (2)/96	1,800(a)	500	3.5	—	—	—	2	1
3/76	3-1/2	81/100 99.5/98.4	2,200(c)	207	3.6	2.5-3.5	90+	—	7	1
9/76	3	(3)/(3) (3)/100	250(h)	—	0.75	—	—	—	2	2
-/72	7-1/2	(3)	773(e)	172	3.2	2.9-3.5	90+	90+	2	2
9/74	5	(3)	668(d)	—	0.7-2	—	—	—	2	2
6/75	4-1/4	(3)	2,200(d)	—	1.2	—	—	—	4	4
4/76	3-1/2	(3)	600(f)	—	0.84	—	—	—	2	2

) - 1978 Dollars
) - 1977 Dollars
) - 1975 Dollars
) - 1974 Dollars
(e) - 1973 Dollars
(f) - 1972 Dollars
(g) - Year not indicated
(h) - Information incomplete

REFERENCES

1. Cogeneration at Navy Bases, Bechtel National, Inc., May 1978. Final Report of Phase I of Navy Energy Guidance Study, Contract N68305-77-C-0003, CEL Publication CR 78.914, DOD Publication AD-A057405.

2. Coal-Fired Boilers at Navy Bases, Bechtel National, Inc., May 1979. Final Report of Phases II and III of Navy Energy Guidance Study, Contract N68305-77-C-0003, CR 79.012.

3. "Checklist for R & M Guidance," Igor Bazovsky & Associates, Canoga Park, CA, 1979. Draft report prepared for the Civil Engineering Laboratory, Port Hueneme under Contract N68305-8342-6427.

4. Gasification at Navy Bases, Bechtel National, Inc., July 1978. Contract N68305-77-C-0021, CEL Publication CR 78.019, DOD Publication AD-A060475.

5. Economic Analysis Handbook, P-442, Naval Facilities Engineering Command, 1975.

6. "Energy Escalation Rates for Short-Term Costing and Life-Cycle Costing," NAVFACENGCOM Ltr 1023B/JNW of 23 August 1976.

7. Economic Analysis and Priority Rating Formulation for Navy Shore Facilities Energy R & D Products, J. M. Slaminski, Civil Engineering Laboratory, NCBC, November 1977.

8. "Economic and Design Factors for Flue Gas Desulfurization Technology," Bechtel National, Inc., for the Electric Power Research Institute (EPRI), Research Project RP1180-9 (in publication).

9. "Failure Rate Sampling Plans and Procedures," Military Standard MIL-STD-690B, with revisions through 12 August 1974, p. 24.

10. Reliability Theory and Practice, Igor Bazovsky, (Englewood Cliffs, N. J.: Prentice-Hall, Inc., 1961).

11. EPA Industrial Boiler FGD Survey: First Quarter 1979, J. Tuttle, et al., PEDCo. Environmental, Inc., for EPA, EPA Report 600/7-79-067b, April 1979.

12. "Simple, Reliable, Efficient, The Chiyoda Thoroughbred 121 Flue Gas Desulfurization System," a brochure of The Chiyoda Chemical Engineering and Construction Co., Ltd., available through Chiyoda International Corporation, Seattle, Washington.

13. "The Chiyoda Thoroughbred 121 Jet Bubbling Flue Gas Desulfurization System, Florida Prototype Plant," a brochure of the Chiyoda Chemical Engineering and Construction Company, Ltd., and Chiyoda International Corporation, July 1978.

14. EPA Evaluation of Bahco Industrial Boiler Scrubber System at Rickenbacker AFB, E. L. Biedell, et al., Research-Cottrell, Inc., for EPA, EPA Report 600/7-78-115, June 1978.

15. "A Demonstration of Pollution Control Technology at Rickenbacker AFB, Ohio," J. B. Rasor, presented to a government working panel in 1978.

16. "R-C/Bahco for Combined SO_2 and Particulate Control," Nicholas J. Stevens, Research-Cottrell Corporation, presented at the Fifth Symposium on Flue Gas Desulfurization for the Environmental Protection Agency, in Las Vegas, Nevada, March 5-8, 1979.

17. EPA Utility FGD Survey: December 1978 - January 1979, M. Smith et al., PEDCo. Environmental, Inc., for EPA, EPA Report 600/7-79-022c, May 1979.

18. "Operating and Status Report, Wellman Lord SO_2 Removal/Allied Chemical SO_2 Reduction Flue Gas Desulfurization Systems at Northern Indiana Public Service Company and Public Service Company of New Mexico," D. W. Ross, James Petrie, and F. W. Link, presented at The Fifth Symposium on Flue Gas Desulfurization for The Environmental Protection Agency, Las Vegas, Nevada, March 5-8, 1979 (available through Davy Powergas, Inc., Lakeland, Florida).

19. Wellman-Lord SO_2 Recovery Process - Flue Gas Desulfurization Plant, U. S. EPA Office of Research and Development Facility, First Progress Report, EPA Technology Transfer Capsule Report, EPA Report 625/2-77-011, 1977.

20. "Status of Sulfur Dioxide Control in Boiler Flue Gas at General Motors Corporation," James H. Frazier, presented at the 1973 Industrial Fuel Conference, Purdue University, West Lafayette, Indiana, October 3, 1973.

21. "Clean Coal Power," a brochure of the General Motors Corporation, 1973.

22. Quarterly reports to The State of Pennsylvania Department of Environmental Resources, Air Branch, Norristown, PA.

23. "Boiler Emissions Control," a brochure of the FMC Corporation's Environmental Equipment Division, 1976.

24. Double Alkali Landfill Tests Evaluation, R. J. Krizek and J. A. Fitzpatrick, April 1976. Technical report of the Department of Civil Engineering of Northwestern University, published as FMC Technical Report 120.

25. "Excellence in environmental engineering . . . through a search for new solutions," a Firestone brochure.

Appendix A

UNIT PRESENT VALUES

A good measure for comparing life-cycle costs of alternative energy options is a unit present value in dollars per million Btu. To obtain a unit present value for an option, it is necessary to compute the entire project life cycle cost of the option, and then divide by the millions of Btu of energy. In this study, the energy basis is energy transferred to heat loads in boilers and fired heaters. This energy is 80 percent of the energy available in the fuel consumed.

THE NAVY LIFE-CYCLE COST METHODOLOGY

The project life-cycle present value is calculated using the methodology of Navy document P-442. That method is summarized as follows:

- The Navy gets its funds from general government tax revenues. Since government projects do not pay taxes, the method does not consider depreciation.

- Funds spent by the Navy represent an opportunity cost to the private sector. That cost is assumed to be 10 percent per annum, in constant dollars. The value of 10 percent was reached by an Institute of Defense Analysis study of the opportunity cost of government projects, after removing the effects of inflation. The fixed 10 percent value for the opportunity cost in the Navy methodology is called the discount rate.

- When there is general inflation of "i" percent per year, the actual annual financing cost of a commercial venture equivalent to a government project would, on the average, be 10 + i. If i is 8 percent, the annual financing cost would be 18 percent. This annual financing cost is commonly referred to in industry as a capital charge. The discount rate is thus equal to the financing capital charge minus the annual inflation. The discount rate can also be referred to as the real rate of return or the time value of money after inflation effects are removed.

- Note that with the current 8 percent per year general inflation, the Navy methodology gives the equivalent of an 18 percent annual financing capital charge. Such a capital charge is consistent with financing costs encountered by public utilities for energy projects. An 18 percent capital charge would result as the sum of income taxes that take into account depreciation over 25 years, 16 percent annual after-tax return on equity, and 11 percent interest and principal on loans (assuming a 1 to 1 debt to equity ratio).

- The Navy economic methodology involves comparing life-cycle costs of all project alternatives in terms of present values. Suppose a cost one year from now in inflated dollars will be X_1. Suppose the annual financing capital charge is d + i, where d is the discount rate and i is the general inflation rate. The present value today of purchase X_1 one year from now is the amount of money invested today at an interest rate of d + i that would equal X_1 one year from now. Let the present value be P. Then:

$$X_1 = P(1 + d + i), \qquad (1)$$

and

$$P = X_1/(1 + d + i). \qquad (2)$$

- The use of present value analysis and a fixed dollar 10 percent discount rate d has the result of washing out general inflation, so that the actual level of general inflation i can be ignored. Suppose an item costs X_0 now. One year from now it will cost:

$$X_1 = X_0\ (1 + i) \qquad (3)$$

The present value now of purchase X_1 made one year from now is

$$P = X_0\ (1 + i)/(1 + d + i) \qquad (4)$$

$$P \cong X_0\ [1/(1 + d)] \qquad (5)$$

The symbol $\cong$ means approximately equal.

Since uncertainties in the true correct values for both d and i exceed the error in the approximation of (5), equation (5) is considered the basic equation of the Navy methodology. This methodology is unusually convenient, because over the life of a typical project, inflation rate i is different each year. By equation (5), none of these annual general inflation rates needs to be considered at all.

- Energy costs are expected to escalate faster than general inflation for the foreseeable future. In the Navy methodology, it is not the total annual percent rise in an energy price which appears explicitly in the present value analysis, but rather the differential inflation, e, (often called differential escalation). Suppose an energy product costs Y_0 today, and its price is rising at an annual inflation rate that totals i + e. Then one year from now the price is expected to be Y_1.

$$Y_1 = Y_0 \ (1 + i + e) \tag{6}$$

The present value today of the purchase Y_1 made one year from now will be:

$$P = Y_1/(1 + d + i) \tag{7}$$

$$P = Y_0 \ (1 + i + e)/(1 + d + i) \tag{8}$$

$$P \cong Y_0[(1 + e)/(1 + d)] \tag{9}$$

Notice how the general inflation rate i has disappeared again as in equation (5). However, the differential inflation rate e does appear explicitly in equation (9).

- Equation (9) includes equation (5) as a special case when the differential inflation e is zero.

- Again, suppose an energy quantity costs Y_0 today. Consider purchasing the same amount n years from today. The present value of that purchase would be:

$$P = Y_0[(1 + e)^n/(1 + d)^n] \tag{10}$$

- Suppose that a certain amount of some commodity now costing Y_0 must be purchased each year from year 1 to year N. The present value at time zero for the entire series of purchases would be:

$$P = Y_0 \left[\sum_{n=1}^{n=N} (1 + e)^n/(1 + d)^n\right] \tag{11}$$

AD-A089 146 BECHTEL NATIONAL INC SAN FRANCISCO CA F/G 13/2
FLUE GAS DESULFURIZATION AT NAVY BASES, NAVY ENERGY GUIDANCE ST--ETC(U)
AUG 80 A I MCCONE N68305-77-C-0003

UNCLASSIFIED CEL-CR-80.023 NL

3 OF 3
AD A
089146

END
DATE
FILMED
10-80
DTIC

- If the same amount were to be purchased each year from year M to year N, the present value at time zero for the series of purchases could be obtained from two series of the form of equation (11) by difference using:

$$\sum_{n=M}^{n=N} = \sum_{n=1}^{n=N} - \sum_{n=1}^{n=M-1} \qquad (12)$$

- The quantity in brackets in equation (10) is called a single amount inflation discount factor. The quantity in brackets in equation (11) is called a cumulative uniform series inflation discount factor.

- The discount factors shown explicitly in equations (10) and (11) are end-of-the-year discount factors. The Navy methodology assigns to a given project year the average of the end-of-year discount factor and a corresponding beginning-of-the-year discount factor (with n in equation (10) replaced by n-1 for year n). This was done because it is not clear when a purchase will be made in a given project year. Therefore, the average occurrence time would be at mid-year. The resulting formulas for the discount factors are slightly more complicated than those shown in equations (10) and (11).

- Notice that in equations (5), (6), (10), and (11) the costs to be inserted are those for year zero. This means that life-cycle costs for a project can be estimated from the cost elements computed at a single point in time called the zero of time.

BECHTEL'S PRESENT VALUES AND UNIT PRESENT VALUES

Table 2-4 in Section 2 shows the details of how present values were calculated in this study.

Once a life-cycle present value has been calculated, it can be divided by the number of million Btu of heat transferred over the operating life to get a unit present value, as is done in Table 2-4.

Some special comments are in order about Bechtel's present values and unit present values:

- For Bechtel's studies, the project zero of time has been taken as the date of the cost prices used.* The date of the commencement of plant operation is then assumed to be some years later, allowing a reasonable amount of time for decision making and financing, and in particular, allowing adequate time for plant construction. Coal conversion plants typically are expected to take 36 months to design and build. Coal boiler plants typically take 24 months. Typically, 50 percent of the project expenditures will be made during the first two-thirds of the construction period. When this is indicated in the project life cycle cash flow analysis, the Navy methodology adequately accounts for what industry calls "interest during construction."

- Bechtel's present values accordingly involve a zero of time that differs from the start of the first year of operation, even though many analyses for the Navy have the start of operations as the zero of time. Because the start of operations in Bechtel's studies will be several years after time zero, the present values at time zero of all operating costs will be lower than they would be if the zero of time occurred at the start of operations.

- For this study, the start of operations occurs at the beginning of the fourth year. The cumulative uniform series for the project years 4 through 28 is calculated by equation (12) from the factors tabulated in Appendix C, for each relevant value of differential inflation rate e, as shown in Table A-1.

---

* For this study, the cost estimate was made in second quarter 1978 dollars .

Table A-1

COMPUTATION OF CUMULATIVE UNIFORM SERIES INFLATION DISCOUNT FACTORS FOR YEARS 4 TO 28

Commodity	General Wages & Prices	Coal	Electricity	Fuel Oil
Differential Inflation Rate	0	5	6	10
Series for Project Years 1 to 28	9.765	15.653	17.427	28.000
Series for Project Years 1 to 3	2.609	2.800	2.839	3.000
Series for Project Years 4 to 28 (Difference)	7.156	12.853	14.588	25.000

SAMPLE CALCULATION

Consider a centralized coal-fired steam generating plant with the following design and operation:

- Four equal-sized stoker boilers with combined design output of 400 x 10^6 Btu/hr
- Two air pollution control systems each designed to 60 percent of the combined flue gas from the boilers, each system containing:
  - Baghouse particulate removal
  - Double alkali flue gas desulfurization
- Coal fuel containing 4 percent sulfur
- Load factor of 33 percent

Table A-2 gives capital and annual costs of the system. Table A-3 shows the resulting calculation of present values and unit present value.

STANDARD NAVFAC UNIT PRESENT VALUES

The Naval Facilities Engineering Command (NAVFAC) examines energy projects with the zero of time at the start of the first year of operations. This is presumably because many small energy projects have relatively short times between initial capital outlay and the start of operations, and the capital costs can be considered to occur in the same project year that energy operations start. When unit present values are calculated in this way, the values are higher than Bechtel's values presented in this study.

It is useful to be able to convert the Bechtel unit present values to a basis approximately equivalent to that of NAVFAC. This can be done by multiplying the Bechtel unit present values by the ratio of the discount factors for zero differential inflation. The NAVFAC discount factor would cover project years 1 to 25. The discount factor from Appendix C of this report is 9.524. Thus, the Bechtel unit present values need merely to be multiplied by:

$$\frac{\text{Discount Factor Yrs 1 to 25}}{\text{Discount Factor Yrs 4 to 28}} = \frac{9.524}{7.156} = 1.3309$$

Table A-2

CAPITAL AND ANNUAL OPERATING COSTS FOR A SAMPLE COAL-FIRED BOILER PLANT WITH AIR POLLUTION CONTROL

		Steam Generation	Air Pollution Control	Total
Capital Costs	Total Construction Cost	16,800	9,400	26,200
	Startup Cost			2,900
	Total Capital Cost			29,100
Annual Operating Costs	Coal at $\$1.41/10^6$ Btu	2,000	—	2,000
	Electricity at $0.033/kWh	50	50	100
	Labor	1,340	680	2,020
	Materials and Supplies	550	740	1,290
	Total Annual Operating Cost			5,410

Costs in thousands of second quarter 1978 dollars

Table A-3

PRESENT VALUE CALCULATION FOR A SAMPLE PLANT

Line Number	Cost Element	Differential Inflation Rate	Project Year	Amount, Thousands of Dollars		Discount Factor	Present Value Thousands of Dollars
				One Time	Recurring		
(1)	First Year Construction	+0	2	9,700		0.867	8,410
(2)	Second Year Construction	+0	3	19,400		0.788	15,287
(3)	Total Investment			29,100			23,697
(4)	Coal	+5	4-28		2,000	12.853	25,706
(5)	Electricity	+6	4-28		100	14.588	1,459
(6)	Operating and Maintenance Labor and Materials	+0	4-28		3,310	7.156	23,686
(7)	Total Operating Cost				5,410		50,851
(8)	Total Project Present Value						74,548
(9)	Energy Available Over 25 Years, 10^9 Btu						28,900
(10)	Energy Unit Present Value, $/$10^6$ Btu						2.58

Base year begins May 1978

Appendix B

CONSTANT DOLLAR LEVELIZED UNIT ENERGY COSTS

Another way to display present value comparisons is in terms of levelized unit energy costs. This method has the advantage of putting the costs into a form that resembles the dollars per million Btu energy costs that are familiar in the private sector. For convenience, the latter are called "current dollar costs of energy."

CURRENT DOLLAR COSTS OF ENERGY

It is instructive to derive the current dollar cost of energy for the case treated in Table A-3.

The analysis involves treating recurring annual costs and capital costs separately.

Recurring Annual Costs

Each of the recurring annual costs in Table A-3 can be divided by the amount of heat transferred annually ($28{,}900 \times 10^9$ Btu/25 years). The results are shown in Table B-1.

Capital Costs

Capital costs are usually converted into an equivalent series of uniform annual charges. The result will be a percentage of the capital cost which is to be added to the recurring annual cost of Table B-1. This is commonly called the capital charge.

Table B-1

CURRENT DOLLARS COST OF ENERGY FOR RECURRING ANNUAL COSTS
(For Case of Table A-2)

Cost Item	Amount, Thousands of Dollars	Dollars per Million Btu*
Coal	2,000	1.73
Electricity	100	0.09
Operating and Maintenance Labor and Materials	3,310	2.86
Total Recurring Operating Costs	5,410	4.68

*1156 x 10^9 Btu Per Year

The way a capital charge is converted into an equivalent annual charge depends on the way the cost of money is defined. Here, two alternatives may be considered:

- In the first, the cost of money is the sum of the time value of money (discount rate) plus the general inflation rate. This would lead to capital charges in the range of 18 to 20 percent per year.

- In the second, the cost of money is the time value of money alone (discount rate). This leads to capital charges in the range of 10 to 12 percent.

In either case, the equivalent series of uniform annual charges has the same present value as the capital cost.

The private sector uses the first type of capital charge in most cases. Naval projects would be analyzed with the second type of capital charges. The resulting increments in current cost of energy for both types of capital charges, are shown in Table B-2.

Table B-2

CURRENT DOLLARS COST OF ENERGY FOR CAPITAL CHARGES

Item	Annual Percent of Investment	Annual Capital Charge	
		Amount, Thousands of Dollars	Dollars Per Million Btu
Private Sectors Actual Inflating Dollars Cost of Money	19.4	5,645	4.88
Navy Analysis Discount Rate with Inflation Removed	11.38	3,312	2.86

Note that the private sector capital charge would be the one actually paid now if the plant in question had just started operating this year. Thus, it is the capital charge that gives the best feel of costs being charged at this time.

For Navy project comparisons, however, only the second kind of capital charge is in the correct ratio to annual costs for life-cycle costing.

CONSTANT DOLLAR LEVELIZED COSTS

The current dollar cost of energy does not take into account any differential inflation of energy costs. Consequently, it cannot represent a fair measure for comparison of energy projects if differential inflation is expected. The current dollar cost does not give sufficient weight to future energy costs, and hence it penalizes projects which have high investment costs, yet which save on future energy costs.

The Navy present value methodology described in Appendix A, on the other hand, does give fair comparisons of projects that include differential inflation. It would be desirable to have a measure that is equivalent to the present value measure, but which resembles the current dollar cost. Constant dollar levelized costs constitute such a measure.

The Navy levelized costs can be called constant dollar levelized costs because the general inflation rate is assumed to be zero. The resulting levelized costs thus take into account differential inflation of energy, but ignore general inflation.

Levelized costs for an energy component in a project's life-cycle costs are obtained simply by multiplying the annual amount and the dollars per million Btu of that component by the ratio of two cumulative uniform series inflation discount factors that appear in the present value analysis of the problem. The ratio is:

$$\left(\frac{\text{Discount factor for energy component}}{\text{Discount factor with zero differential inflation}}\right)$$

In Table A-3, the discount factor for operating and maintenance labor and material (with zero differential inflation) is 7.156. For coal (with 5 percent differential inflation), the discount factor is 12.853. Therefore, the appropriate levelizing multiplier is (12.853/7.156) = 1.7961.

Table B-3 presents the levelized costs for the case of Table A-3.

Capital costs have been included in the levelized cost display of Table B-3. Capital contributions to the levelized costs are calculated in the same way as for other cost elements:

$$\left(\frac{\text{Discount factor for cost element}}{\text{Discount factor for recurring costs with zero differential inflation}}\right)$$

The levelized costs of elements in Table B-3 have the following characteristics:

- They are in the same ratio to each other as are the present value costs.
- The labor and materials recurring costs are unchanged by the levelizing process.

Table B-3

CONSTANT DOLLAR LEVELIZED COSTS
(From Table A-3)

Cost Element	Multiplier	Constant Dollar Levelized Costs	
		Annual Cost Amount, Thousands of Dollars	Dollars per Million Btu
First Year Investment	0.1212	1,176	1.02
Second Year Investment	0.1101	2,136	1.84
Total Investment	0.1138	3,312	2.86
Coal	1.796	3,592	3.11
Electricity	2.039	204	0.18
Operating and Maintenance Labor and Material	1.0	3,310	2.86
Total Project		10,418	9.01

The levelized annual amounts in Table B-3 could have been obtained directly by dividing all present values in Table A-3 by 7.156, the discount factor for the labor and materials cost element.

Table B-4 presents the three possible ways for expressing dollars per million Btu that have been suggested in this appendix:

- Current dollar costs with private sector capital charge
- Current dollar costs with Navy capital charge
- Levelized costs

It is axiomatic that a present value comparison is better for comparing life cycle costs than any other. The levelized costs, which are merely present values redisplayed another way, are clearly the best of the three measures in Table B-4. It then becomes clear that private-sector current dollar costs highly distort project comparisons. Capital contributions

Table B-4

THREE FORMS OF DOLLARS PER 10^6 BTU BOILER OUTPUT
(Based on Table A-3)

Cost Element	Current Dollar Costs, Private Sector Capital Charge	Current Dollar Costs, Navy Capital Charge	Constant Dollar Levelized Costs
Investment	4.88	2.86	2.86
Coal	1.73	1.73	3.11
Electricity	0.09	0.09	0.18
Operating and Maintenance Labor and Materials	2.86	2.86	2.86
Total Project	9.56	7.54	9.01

to costs are exaggerated, while energy costs are undervalued. Because of this, industry is moving away from current dollar comparisons to discounted cash flow analyses for comparing alternative projects. The levelized cost method above is equivalent to a discounted cash flow analysis.

Appendix C

DISCOUNT FACTOR TABLES

The following tables are reprinted from Navy Publications P-442.

Table C-1

PROJECT YEAR 0% DIFFERENTIAL INFLATION-DISCOUNT FACTORS*

Discount Rate = 10%

Project Year	Single Amount	Cumulative Uniform Series
1	0.954	0.954
2	0.867	1.821
3	0.788	2.609
4	0.717	3.326
5	0.652	3.977
6	0.592	4.570
7	0.538	5.108
8	0.489	5.597
9	0.445	6.042
10	0.405	6.447
11	0.368	6.815
12	0.334	7.149
13	0.304	7.453
14	0.276	7.729
15	0.251	7.980
16	0.226	8.209
17	0.208	8.416
18	0.189	8.605
19	0.172	8.777
20	0.156	8.933
21	0.142	9.074
22	0.129	9.203
23	0.117	9.320
24	0.107	9.427
25	0.097	9.524
26	0.088	9.612
27	0.080	9.692
28	0.073	9.765
29	0.066	9.831
30	0.060	9.891

* These factors are to be applied to cost elements which are anticipated to escalate at the same rate as the general price level.

Table C-2

PROJECT YEAR 5% DIFFERENTIAL INFLATION-DISCOUNT FACTORS*

Discount Rate = 10%

Project Year	Single Amount	Cumulative Uniform Series
1	0.977	0.977
2	0.933	1.910
3	0.890	2.800
4	0.850	3.650
5	0.811	4.461
6	0.774	5.235
7	0.739	5.974
8	0.706	6.680
9	0.673	7.353
10	0.643	7.996
11	0.614	8.610
12	0.586	9.196
13	0.559	9.755
14	0.534	10.288
15	0.509	10.798
16	0.486	11.284
17	0.464	11.748
18	0.443	12.191
19	0.423	12.614
20	0.404	13.018
21	0.385	13.403
22	0.368	13.771
23	0.351	14.122
24	0.335	14.458
25	0.320	14.777
26	0.305	15.083
27	0.292	15.374
28	0.278	15.653
29	0.266	15.918
30	0.254	16.172

* These factors are to be applied to cost elements which are anticipated to escalate at a rate 5 percent faster than general price levels.

Table C-3

PROJECT YEAR 6% DIFFERENTIAL INFLATION DISCOUNT FACTORS*

Discount Rate = 10%

Project Year	Single Amount	Cumulative Uniform Series
1	0.982	0.982
2	0.946	1.928
3	0.912	2.839
4	0.878	3.718
5	0.847	4.564
6	0.816	5.380
7	0.786	6.166
8	0.757	6.923
9	0.730	7.653
10	0.703	8.357
11	0.678	9.035
12	0.653	9.688
13	0.629	10.317
14	0.607	10.924
15	0.584	11.508
16	0.563	12.071
17	0.543	12.614
18	0.523	13.137
19	0.504	13.641
20	0.486	14.127
21	0.468	14.595
22	0.451	15.046
23	0.435	15.480
24	0.419	15.899
25	0.404	16.303
26	0.389	16.692
27	0.375	17.066
28	0.361	17.427
29	0.348	17.775
30	0.335	18.111

* These factors are to be applied to cost elements which are anticipated to escalate at a rate 6 percent faster than general price levels.

Table C-4

PROJECT YEAR 10% DIFFERENTIAL INFLATION-DISCOUNT FACTORS*

Discount Rate = 10%

Project Year	Single Amount	Cumulative Uniform Series
1	1.000	1.000
2	1.000	2.000
3	1.000	3.000
4	1.000	4.000
5	1.000	5.000
6	1.000	6.000
7	1.000	7.000
8	1.000	8.000
9	1.000	9.000
10	1.000	10.000
11	1.000	11.000
12	1.000	12.000
13	1.000	13.000
14	1.000	14.000
15	1.000	15.000
16	1.000	16.000
17	1.000	17.000
18	1.000	18.000
19	1.000	19.000
20	1.000	20.000
21	1.000	21.000
22	1.000	22.000
23	1.000	23.000
24	1.000	24.000
25	1.000	25.000
26	1.000	26.000
27	1.000	27.000
28	1.000	28.000
29	1.000	29.000
30	1.000	30.000

* These factors are to be applied to cost elements which are anticipated to escalate at a rate 10 percent faster than general price levels.

Appendix D

TOTAL CONSTRUCTION COSTS OF AIR POLLUTION CONTROL SYSTEMS

Table D-1

TOTAL CONSTRUCTION COSTS,*
AIR POLLUTION CONTROL SYSTEMS FOR SINGLE DECENTRALIZED BOILERS**
(December 1979 Update of Table 5-3 of Final Report for Phases II and III)

	0.5% S Coal				2% S Coal				4% S Coal			
Boiler Output, 10^6 Btu/hr	25	50	100	200	25	50	100	200	25	50	100	200
Particulate Removal System												
Equipment	210	300	520	820	210	300	520	820	210	300	520	820
Labor	180	260	450	730	180	260	450	730	180	260	450	730
Subtotal	390	560	970	1,550	390	560	970	1,550	390	560	970	1,550
Desulfurization System												
Equipment	--	--	--	--	450	550	810	1,350	480	720	1,260	1,990
Labor	--	--	--	--	380	510	750	1,230	450	640	1,100	1,790
Subtotal	--	--	--	--	830	1,060	1,560	2,580	930	1,360	2,360	3,780
Total Air Pollution Control	390	560	970	1,550	1,220	1,620	2,530	4,130	1,320	1,920	3,330	5,330

*Thousands of second quarter 1978 dollars.
**For each boiler, one air pollution control system capable of processing 100 percent of boiler flue gas output.

Table D-2

TOTAL CONSTRUCTION COSTS*
AIR POLLUTION CONTROL SYSTEMS FOR CENTRAL BOILER PLANTS**
(December 1979 Update of Table 5-4 of Final Report for Phases II and III)

	0.5% S Coal				2% S Coal				4% S Coal			
Boiler Output, 10^6 Btu/hr	100	200	400	800	100	200	400	800	100	200	400	800
Particulate Removal System												
Equipment	660	1,000	1,470	2,590	660	1,000	1,470	2,590	660	1,000	1,470	2,590
Labor	590	900	1,330	2,310	590	900	1,330	2,310	590	900	1,330	2,310
Subtotal	1,250	1,900	2,800	4,900	1,250	1,900	2,800	4,900	1,250	1,900	2,800	4,900
Desulfurization System												
Equipment	--	--	--	--	1,080	1,710	3,000	4,530	1,400	2,190	3,480	5,750
Labor	--	--	--	--	970	1,590	2,700	4,170	1,250	2,010	3,120	5,150
Subtotal	--	--	--	--	2,050	3,300	5,700	8,700	2,650	4,200	6,600	10,900
Total Air Pollution Control	1,250	1,900	2,800	4,900	3,300	5,200	8,500	13,600	3,900	6,100	9,400	15,800

*Thousands of second quarter 1978 dollars.
**Air pollution control equipment in two trains, each capable of processing 60 percent of the boiler plant flue gas output.

Appendix E

SUPPLEMENTAL COST TABLES FOR CURRENT TECHNOLOGIES

Table E-1

APPROXIMATE CAPITAL AND ANNUAL OPERATING COSTS FOR
400 MILLION BTU PER HOUR FACILITIES
(25% Load Factor)

Cost Item	Lime-stone	Lime	Double Alkali	Soda Liquor, Solid Wastes	Soda Liquor, Solid Wastes	Wellman-Lord/Allied Chemical
Approximate Capital Cost						
Total Construction Cost	6,600	6,600	6,600	6,600	3,300	15,000
Startup	730	730	730	730	360	1,650
Total Capital	7,330	7,330	7,330	7,330	3,660	16,650
Annual Operating Cost						
Electricity	81	70	34	81	35	70
Natural Gas	—	—	—	—	—	51
Steam	113	113	113	113	113	330
Water	4	4	4	4	6	73
Chemicals	96	213	207	393	393	19
Operating Labor	380	380	380	380	290	540
Operating Supplies	30	30	30	30	20	43
Maintenance Labor	132	132	132	132	66	300
Maintenance Material	264	264	264	264	132	600
Waste Disposal Contract	48	44	48	74	148	2
Total Annual Operating Cost	1,148	1,250	1,212	1,471	1,203	2,028
Annual Operating $/10^6$ Btu	1.31	1.43	1.38	1.68	1.37	2.32

Costs in thousands of second quarter 1978 dollars.
Annual dollars per million Btu do not contain capital charges.
Annual boiler output is 876 billion Btu.
Annual flows used for annual operating costs are 1/2 of those in Table 3-1 on page 3-17.

Table E-2

APPROXIMATE CAPITAL AND ANNUAL OPERATING COSTS FOR
200 MILLION BTU PER HOUR FACILITIES
(25% Load Factor)

Cost Item	Lime-stone	Lime	Double Alkali	Soda Liquor, Solid Wastes	Soda Liquor, Liquid Wastes
Approximate Capital Cost					
Total Construction Cost	4,200	4,200	4,200	4,200	2,100
Startup	460	460	460	460	230
Total Capital	4,660	4,660	4,660	4,660	4,660
Annual Operating Cost					
Electricity	41	35	17	41	17
Natural Gas	—	—	—	—	—
Steam	57	57	57	57	57
Water	2	2	2	2	3
Chemicals	48	107	104	197	197
Operating Labor	320	320	320	320	260
Operating Supplies	26	26	26	26	21
Maintenance Labor	84	84	84	84	42
Maintenance Material	168	168	168	168	84
Waste Disposal Contract	24	22	24	37	74
Total Annual Operating Cost	770	821	802	932	755
Annual Operating $/10^6$ Btu	1.76	1.87	1.83	2.13	1.72

Costs in thousands of second quarter 1978 dollars.
Annual operating dollars per million Btu do not contain capital charges.
Annual boiler output is 438 billion Btu.
Annual flows used for annual operating costs are 1/4 of those in Table 3-1 on page 3-17.

Table E-3

APPROXIMATE CAPITAL AND ANNUAL OPERATING COSTS FOR
100 MILLION BTU PER HOUR FACILITIES
(25% Load Factor)

Cost Item	Lime-Stone	Lime	Double Alkali	Soda Liquor, Solid Wastes	Soda Liquor, Liquid Wastes
Approximate Capital Cost					
Total Construction Cost	2,360	2,360	2,360	2,360	1,180
Startup	260	260	260	260	130
Total Capital	2,620	2,620	2,620	2,620	1,310
Annual Operating Cost					
Electricity	21	18	9	21	9
Natural Gas	--	--	--	--	--
Steam	29	29	29	29	29
Water	1	1	1	1	1
Chemicals	24	54	52	99	99
Operating Labor	246	246	246	246	200
Operating Supplies	20	20	20	20	18
Maintenance Labor	52	52	52	52	26
Maintenance Material	105	105	105	105	52
Waste Disposal Contract	12	11	12	18	37
Total Annual Operating Cost	510	536	526	591	491
Annual Operating $\$/10^6$ Btu	2.33	2.45	2.40	2.70	2.24

Costs in thousands of second quarter 1978 dollars.
Annual operating dollars per million Btu do not contain capital charges.
Annual boiler output is 219 billion Btu.
Annual flows used for annual operating costs are 1/8 of those in Table 3-1 on page 3-17

Table E-4

APPROXIMATE CAPITAL AND ANNUAL OPERATING COSTS FOR
50 MILLION BTU PER HOUR FACILITIES
(25% Load Factor)

Cost Item	Lime-Stone	Lime	Double Alkali	Soda Liquor, Solid Wastes	Soda Liquor, Liquid Wastes
Approximate Capital Cost					
Total Construction Cost	1,360	1,360	1,360	1,360	680
Startup	150	150	150	150	75
Total Capital	1,510	1,510	1,510	1,510	755
Annual Operating Cost					
Electricity	11	9	5	11	5
Natural Gas	—	—	—	—	—
Steam	14	14	14	14	14
Water	—	—	—	—	—
Chemicals	12	27	26	50	50
Operating Labor	220	220	220	220	200
Operating Supplies	18	18	18	18	16
Maintenance Labor	27	27	27	27	14
Maintenance Material	54	54	54	54	27
Waste Disposal Contract	6	5	6	9	18
Total Annual Operating Cost	362	374	370	403	344
Annual Operating $/10^6$ Btu	3.31	3.42	3.38	3.68	3.14

Costs in thousands of second quarter 1978 dollars.
Annual operating dollars per million Btu do not contain capital charges.
Annual boiler output is 110 billion Btu.
Annual flows used for annual operating costs are 1/16 those in Table 3-1 on page 3-17.

Table E-5

APPROXIMATE CAPITAL AND ANNUAL OPERATING COSTS FOR
25 MILLION BTU PER HOUR FACILITIES
(25% Load Factor)

Cost Item	Lime-Stone	Lime	Double Alkali	Soda Liquor, Solid Wastes	Soda Liquor, Liquid Wastes
Approximate Capital Cost					
Total Construction Cost	930	930	930	930	465
Startup	100	100	100	100	50
Total Capital	1,030	1,030	1,030	1,030	515
Annual Operating Cost					
Electricity	6	5	3	6	3
Natural Gas	—	—	—	—	—
Steam	7	7	7	7	7
Water	—	—	—	—	—
Chemicals	6	14	13	25	25
Operating Labor	194	194	194	194	180
Operating Supplies	16	16	16	16	14
Maintenance Labor	19	19	19	19	9
Maintenance Material	37	37	37	37	19
Waste Disposal Contract	3	3	3	5	9
Total Annual Operating Cost	288	295	292	309	266
Annual Operating $\$/10^6$ Btu	5.26	5.39	5.33	5.64	4.86

Costs in thousands of second quarter 1978 dollars.
Annual operating dollars per million Btu do not contain capital charges.
Annual boiler output is 55 billion Btu.
Annual flows used for annual operating costs are 1/32 of those in Table 3-1 on page 3-17.

Table E-6

APPROXIMATE PRESENT VALUES FOR CURRENT TECHNOLOGIES AT 50 PERCENT LOAD FACTOR

Installation Size	Cost Item	Lime-Stone	Lime	Double Alkali	Soda Liquor, Solid Wastes	Soda Liquor, Liquid Wastes	Wellman-Lord/ Allied Chemical
400×10^6 Btu/hr	Investment	5,969	5,969	5,969	5,969	2,980	13,558
	Electricity	2,349	2,028	977	2,363	1,021	2,042
	Natural Gas	—	—	—	—	—	2,550
	Other Annual Operating Costs	9,496	11,099	11,035	14,112	13,038	16,666
	Total Present Value	17,814	19,096	17,981	22,444	17,039	34,816
	Unit Present Value, $\$/10^6$ Btu	0.41	0.44	0.41	0.51	0.39	0.79
200×10^6 Btu/hr	Investment	3,672	3,672	3,672	3,672	1,836	
	Electricity	1,182	1,021	496	1,182	511	
	Natural Gas	—	—	—	—	—	
	Other Annual Operating Costs	6,147	6,956	6,941	8,086	7,950	
	Total Present Value	11,001	11,649	11,109	12,940	10,297	
	Unit Present Value $\$/10^6$ Btu	0.50	0.53	0.51	0.59	0.47	
100×10^6 Btu/hr	Investment	2,065	2,065	2,065	2,065	1,032	
	Electricity	598	511	248	598	248	
	Natural Gas	—	—	—	—	—	
	Other Annual Operating Costs	3,964	4,372	4,365	5,124	4,623	
	Total Present Value	6,627	6,948	6,678	7,787	5,903	
	Unit Present Value, $\$/10^6$ Btu	0.61	0.63	0.61	0.71	0.54	
50×10^6 Btu/hr	Investment	1,190	1,190	1,190	1,190	595	
	Electricity	306	263	131	306	131	
	Natural Gas	—	—	—	—	—	
	Other Annual Operating Costs	2,755	2,963	2,963	3,335	3,027	
	Total Present Value	4,251	4,416	4,284	4,831	3,753	
	Unit Present Value, $\$/10^6$ Btu	0.78	0.81	0.78	0.88	0.69	
25×10^6 Btu/hr	Investment	812	812	812	812	406	
	Electricity	160	131	73	160	73	
	Natural Gas	—	—	—	—	—	
	Other Annual Operating Costs	2,132	2,233	2,233	2,426	2,175	
	Total Present Value	3,104	3,176	3,118	3,398	2,654	
	Unit Present Value, $\$/10^6$ Btu	1.13	1.16	1.14	1.24	0.97	

Present values in thousands of second quarter 1978 dollars.

Table E-7

APPROXIMATE PRESENT VALUES FOR CURRENT TECHNOLOGIES AT 25 PERCENT LOAD FACTOR

Installation Size	Cost Item	Lime-stone	Lime	Double Alkali	Soda Liquor, Solid Wastes	Soda Liquor, Liquid Wastes	Wellman-Lord/ Allied Chemical
400×10^6 Btu/hr	Investment	5,969	5,969	5,969	5,969	2,980	13,558
	Electricity	1,182	1,021	496	1,182	511	1,021
	Natural Gas	—					1,275
	Other Annual Operating Costs	7,635	8,444	8,430	9,947	8,344	13,646
	Total Present Value	14,786	15,434	14,895	17,098	11,835	29,500
	Unit Present Value, $/10^6 Btu	0.68	0.70	0.68	0.78	0.54	1.35
200×10^6 Btu/hr	Investment	3,672	3,672	3,672	3,672	1,836	
	Electricity	598	511	248	598	248	
	Natural Gas	—	—	—	—	—	
	Other Annual Operating Costs	5,217	5,625	5,617	6,376	5,274	
	Total Present Value	9,487	9,808	9,537	10,646	7,358	
	Unit Present Value, $/10^6 Btu	0.87	0.90	0.87	0.97	0.67	
100×10^6 Btu/hr	Investment	2,065	2,065	2,065	2,065	1,032	
	Electricity	306	263	131	306	131	
	Natural Gas	—	—	—	—	—	
	Other Annual Operating Costs	3,499	3,707	3,700	4,079	3,449	
	Total Present Value	5,870	6,035	5,896	6,450	4,612	
	Unit Present Value, $/10^6 Btu	1.07	1.10	1.08	1.18	0.84	
50×10^6 Btu/hr	Investment	1,190	1,190	1,190	1,190	595	
	Electricity	160	131	73	160	73	
	Natural Gas	—	—	—	—	—	
	Other Annual Operating Costs	2,512	2,612	2,612	2,805	2,425	
	Total Present Value	3,862	3,933	3,875	4,155	3,093	
	Unit Present Value, $/10^6 Btu	1.41	1.44	1.42	1.52	1.13	
25×10^6 Btu/hr	Investment	812	812	812	812	406	
	Electricity	88	73	44	88	44	
	Natural Gas	—	—	—	—	—	
	Other Annual Operating Costs	2,018	2,075	2,068	2,168	1,882	
	Total Present Value	2,918	2,960	2,924	3,068	2,332	
	Unit Present Value, $/10^6 Btu	2.13	2.16	2.14	2.24	1.70	

Present values in thousands of second quarter 1978 dollars.

Appendix F

QUESTIONNAIRE

QUESTIONNAIRE
INDUSTRIAL FLUE GAS SCRUBBER INSTALLATIONS
NAVY CEL/BECHTEL ENERGY GUIDANCE STUDY

1. GENERAL

1.1 Identification

Location

Owner/Operator

Manufacturer

Capacity

Type of process

Date of installation

1.2 Decision to Install

Background/reason for making installation

Impact of environmental limitations

Benefits (environmental, savings of coal costs)

Payback period projected

Type of financing (gov't, private)

1.3 <u>Nominal Technical Information</u>

Design life

Length of service

Type of coal and sulfur content

Type of boilers (Stoker, pulverized coal)

2. ECONOMICS

Capital cost

Operating cost

Operating labor cost

Maintenance cost

Maintenance labor cost

Materials cost

Electricity cost

3. EFFICIENCIES

SO_2 removal efficiency

Sorbent consumption rate and percent utilized

Power requirements

Steam or heat or fuel requirements

4. CONFIGURATION

4.1 Trains, Excess Capacities, Spares

Number of scrubbing trains

Excess capacity capability

Components spared

4.2 Critical Parts

(Items of known short life kept on hand because of local supply uncertainty)

5. OPERATING HISTORY

5.1 Stresses Over Use Life

Ambient temperature extremes

Other environmental extremes

Corrosive contaminant levels (e.g. chlorides)

Coal-sulfur level extremes

Flue gas rate extremes

Other significant operating extremes

Do boiler, scrubber operate continuously

5.2 Operating Data

Sensitivity to particulate loading

Annual downtime

Chronology of operating problems and solutions

6. RELIABILITY

6.1 Failure Modes and Effects

Types of malfunctions

Malfunction mode and cause

Effect of failure on system

Unusual stress conditions

Corrective action

6.2 Time Before Failure

For each malfunction,
time since last such failure,
or frequency of failure type

7. MAINTAINABILITY

7.1 Preventive/Scheduled Maintenance

Preventive adjustments/replacements

- lubrication
- cleaning
- unclogging
- replacing high wear/ short life parts

7.1 Preventive/Scheduled Maintenance - continued

Who performs? (operations crew
or maintenance crew)

Annual manhours preventive

Types of scheduled adjustments,
repairs

How often scheduled

Length of down period

Annual manhours scheduled

7.2 Time to Repair Failure

How long for repair
crew to correct
each type of failure

7.3 Supply Problems

Due to manufacturers

Due to own purchasing
delays

8. AVAILABILITY/DEPENDABILITY

Annual nonoperating hours
due to

- Boiler nonoperation
- Scheduled scrubber maintenance
- Emergency scrubber maintenance
- Delays waiting for crew assignment
- Delays in supply of parts
- Other administrative delays

9. OPERABILITY

9.1 Operability Data

Operating personnel requirements

Operations requiring close tolerance manual control

Operations requiring quick operator action to avert malfunction

9.2 Special Training Requirements